Lawrence Berkeley National Laboratory

Final Report on Phase 2 Results

2025 California Demand Response Potential Study

Charting California's Demand Response Future

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The imminent risks of climate change demand rapid decarbonization of the power sector. California has energetically embraced this imperative, targeting emission reductions of 40% below 1990 levels by 2030.This study from the Lawrence Berkeley National Laboratory (LBNL) begins to reveal the role of demand response in reaching that goal.

Aspects of how this study was done and what it tells us deserve emphasis. The study begins with a ground breaking data set. Leveraging California's advanced metering infrastructure, electricity usage data from over 200,000 smart meters has been mined and organized into clusters representative of California's electricity customers. This vivid characterization reveals the contours and nuances of how electricity is consumed by members of a highly diverse population, a step which is critical to any effort attempting to change how that consumption occurs for the better.

Building on this foundation LBNL has embraced the challenge of our rapidly evolving technological landscape. The study models traditional tools of demand response, such as industrial pumps, HVAC and lighting, while also pushing ahead into electric vehicles, batteries, and data centers. The result is a broad suite of possible responsive technologies and systems, the operation of which may be altered at strategic times to the advantage of the customer and public.

Adding to its breakthroughs in characterizing customers and technologies, the study provides another big step forward in framing its results. LBNL replaces a traditional monolithic concept of demand response with a more nuanced alternative: shape, shift, shed, and shimmy – four flavors of demand response, each with a unique character complementing the needs of the grid.

Each of these innovations in how the study was done make it possible to better understand demand response's potential and future value. The most prominent conclusion of the study is that traditional demand response – that which reduces hot summer peak demand – may be of limited value in the future, a conclusion, which is equally true for generators of a similar operating profile. In its place, the study finds a need to shift customer usage patterns to complement abundant day-time solar generation. Similarly, the study finds that demand response is not of equal value in all places, but rather of greater value in targeted locations. These conclusions deserve careful consideration and, where reasonable, action.

This study's results give me confidence in the trajectory of California's demand response policies, while reminding us there is work to be done yet. The California Public Utilities Commission has already taken critical steps, including:

- investing in the integration of demand response into wholesale markets where it can be dispatched consistent with locational marginal prices;

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- enabling a new generation of demand response aggregators capable of delivering tailored options that work for customers with unique needs,
- committing to default time of use rates for all customers by 2019; and
- committing to greater differentiation of incentives based on relative locational value.

Each of these steps will do as the study suggests: increase the targeting of demand response to times and locations of greater value and thereby serving grid needs. However, it is not enough to be merely on the right trajectory; considerable follow through and attention to detail will be required. It is my hope that this rich study will support that ongoing effort and that our cause will be sustained.

I applaud the Lawrence Berkeley National Lab's research team for the first rate work, as well as the many contributors on which they relied. It's my pleasure to commend their work with compliments to all stakeholders with an interest in understanding and helping realize the full potential of demand response.

Michel P. Florio
Commissioner
California Public Utilities Commission

DISCLAIMER

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List of Abbreviations

AAEE	Additional achievable energy efficiency
AMI	Advanced metering infrastructure
AS	Ancillary services
BAA	Balancing authority area
BAU	Business-as-usual
BEV	Battery electric vehicle
BTM	Behind-the-meter
CAISO	California Independent System Operator
CBECS	Commercial Buildings Energy Consumption Survey
CEC	California Energy Commission
CEUS	Commercial End-Use Survey
CPP	Critical peak pricing
CPUC	California Public Utilities Commission
C&I	Commercial and Industrial
DER	Distributed Energy Resource
DLC	Direct load control
DOE	U.S. Department of Energy
DR	Demand response
DRAM	Demand response auction mechanism
DRP	Distributed resource planning
DRRC	Demand Response Research Center
DSM	Demand-side management
EE	Energy efficiency
EIA	Energy Information Administration
EUI	Energy use intensity
EV	Electric vehicle
GW	Gigawatt
HVAC	Heating, ventilation and air-conditioning
IDSM	Integrated demand-side management
IOU	Investor-owned utility
ISO	Independent system operator
IT	Information technology
JASC	Joint Agency Steering Committee
kW	Kilowatt
kWh	Kilowatt-hour
kW-yr	Kilowatt-year
LAP	Load aggregation point
LBNL	Lawrence Berkeley National Laboratory
LED	Light-emitting diode
LLNL	Lawrence Livermore National Laboratory
LMP	Locational marginal price
LSE	Load-serving entity
LTPP	Long-term procurement plan
MECS	Manufacturing Energy Consumption Survey

MW	Megawatt
NAICS	North American Industry Classification System
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NOAA	National Oceanographic and Atmospheric Administration
O&M	Operations and maintenance
OIR	Order instituting rulemaking
OpenADR	Open automated demand response
PAC	Program administrator cost
PDR	Proxy demand resource
PCM	Production cost modeler
PDR	Proxy demand resource
PG&E	Pacific Gas and Electric Company
PHEV	Plug-in hybrid vehicle
PV	Photovoltaic
R&D	Research and development
RA	Resource adequacy
RASS	Residential Appliance Saturation Survey
RDRR	reliability demand response resource
RECS	Residential Energy Consumption Survey
RPS	Renewable portfolio standard
SCADA	Supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMART T-Stats	Smart communicating thermostat
SONGS	San Onofre Nuclear Generating Station
Sub-LAP	Sub-load aggregation point
TAG	Technical Advisory Group
T&D	Transmission and distribution
TOU	Time-of-use
TPP	Transmission planning process
TRC	Total resource cost

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1. Executive Summary

California's legislative and regulatory goals for renewable energy are changing the power grid's dynamics. Increased variable generation resource penetration connected to the bulk power system, as well as, distributed energy resources (DERs) connected to the distribution system affect the grid's reliable operation over many different time scales (e.g., days to hours to minutes to seconds). As the state continues this transition, it will require careful planning to ensure resources with the right characteristics are available to meet changing grid management needs.

Demand response (DR) has the potential to provide important resources for keeping the electricity grid stable and efficient, to defer upgrades to generation, transmission and distribution systems, and to deliver customer economic benefits. **This study estimates the potential size and cost of future DR resources for California's three investor-owned utilities** (IOUs): Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

Our goal is to provide data-driven insights as the California Public Utilities Commission (CPUC) evaluates how to enhance DR's role in meeting California's resource planning needs and operational requirements. We address two fundamental questions:

1. What cost-competitive DR service types will meet California's future grid needs as it moves towards clean energy and advanced infrastructure?
2. What is the size and cost of the expected resource base for the DR service types?

Demand response operates across a range of timescales from transient responses in seconds to long-run shifts in daily behavior, and the value created by DR depends on the timescale of the response. This dynamic necessitated a new framework for potential study analysis, and we developed a supply curve modeling framework to express the availability of system-level grid services from distributed resources, based on large samples of Smart Meter Load Shapes. To facilitate comparisons between the cost and value created from having a diverse set of flexible loads, we created a new DR services taxonomy and an analytic framework that groups these services into four core categories: **Shape**, **Shift**, **Shed** and **Shimmy**.

- **Shape** captures DR that reshapes customer load profiles through price response or on behavioral campaigns—"load-modifying DR"—with advance notice of months to days.

- **Shift** represents DR that encourages the movement of energy consumption from times of high demand to times of day when there is a surplus of renewable generation. Shift could smooth net load ramps associated with daily patterns of solar energy generation.
- **Shed** describes loads that can be curtailed to provide peak capacity and support the system in emergency or contingency events—at the statewide level, in local areas of high load, and on the distribution system, with a range in dispatch advance notice times.
- **Shimmy** involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.

1.1. Study Background

The CPUC Energy Division funded this study to support DR policymaking, concurrent with rulemaking R.013-09-011. Based on the current policymaking process needs, we estimated how DR could provide grid services in 2020 and 2025, across a range of scenarios for DR market and technology options. This report summarizes our results after the second of two project phases.

- In Phase 1, we studied peak shedding (conventional) DR that qualifies for system and local resource adequacy capacity credit and compared DR costs with avoided cost estimates for conventional generation, transmission, and distribution.
- In Phase 2, we broadened our study to cover more advanced technology to enable fast-response DR and help meet California's future capacity, energy, and ancillary services.

This study focuses on system-level services (i.e., services that meet transmission system level needs and could be organized by the California Independent System Operator (CAISO)) to help inform the DR "bifurcation" process. Bifurcation is an organizing concept for advancing DR policy. It refers to integrating some resources into the CAISO markets for direct dispatch to meet system needs ("supply" DR) with other resources that are controlled or dispatched outside the market ("load-modifying" DR).

1.2. Approach

The analytical framework developed for this study forecasts levelized cost supply and demand curves for the years 2020 and 2025, and for four defined DR services types: Shape, Shift, Shed, and Shimmy. The analysis employs a bottom-up, customer end-use load forecasting model with tight integration between weather, loads and renewable generation patterns (constituting net load). These are in turn, combined with a detailed DR cost database to express DR supply curves for each grid service, showing how much DR is expected to be available across a range of costs.

There are three primary methods we use to assess DR opportunities for an expected near-future

grid:

- **LBNL-Load** examines IOU-provided load data and demographics (~11 million customers) and groups them into cohorts, or "clusters," based on the similarity of their demographic and load. LBNL-Load examines hourly load data (from ~220,000 customers) to define characteristic load profiles for the clusters, as total load and by end uses. LBNL-Load forecasts loads for the years 2020 and 2025 according to the 2015 Integrated Energy Policy Report.
- **DR-Path** generates a range of DR pathways based on the load forecasts from LBNL-Load. These pathways represent likely futures, given technology adoption, DR participation, and cost projections for existing and emerging technologies. The DR-Path tool can be used to develop annual supply curves to estimate the available DR in a given case.
- The **Renewable Energy Solutions** (RESOLVE) model is used to estimate a set of value benchmarks for each type of DR to the system based on the avoided cost of investment and operation when DR is available for use. RESOLVE is a power system investment and operations model that uses optimization to minimize costs while meeting planning and operational requirements, including renewable generation targets and resource adequacy constraints among others. The cases modeled in RESOLVE are run separately from LBNL-Load and DR-PATH, reflecting the different purpose and architecture of the model and enabling our integrated economic analysis. In RESOLVE a range of DR availability scenarios were run to estimate the value of DR for reducing the overall cost of the power system for two benchmark cases describing the level of expected renewable energy curtailment: low and high.

The DR-Path results/output are supply curves that express the available quantity of particular DR resources across a range of possible costs. We use two methods to express DR costs—both shown in Figure 1:

- **The Price Referent Approach:** This is the cost of procuring an alternative resource that could meet the same needs as the DR service (e.g., a natural gas combustion turbine that could carry peak load instead of peak Shed DR). If you assume that these resources will need to be procured one way or another, the price referent effectively sets a DR cost ceiling for procurement.
- **The System Levelized Value Approach:** This compares supply with some estimated "levelized value" to the grid across a range of possible DR services. The levelized value could be thought of as load demand curves. The intersection of a supply curve and levelized value demand curve could represent a procurement target or expected market outcome if the incentives were aligned completely, linking DR aggregators with value streams from the service.

Both approaches provide DR "cost-effectiveness" estimates—meaning the DR resource procurement where the costs are outweighed by benefits. We refer to the results as "cost-effective DR," but our results should not be taken as a literal application of the "cost-effectiveness protocols" used by the CPUC to assess utility programs. The DR cost estimates include the total gross cost of the resource. We adjust these to simulate revenue opportunities available to DR aggregators or customers: revenue from ISO markets, site-level co-benefits from investment in control technology, and payments from service to the distribution system operator.

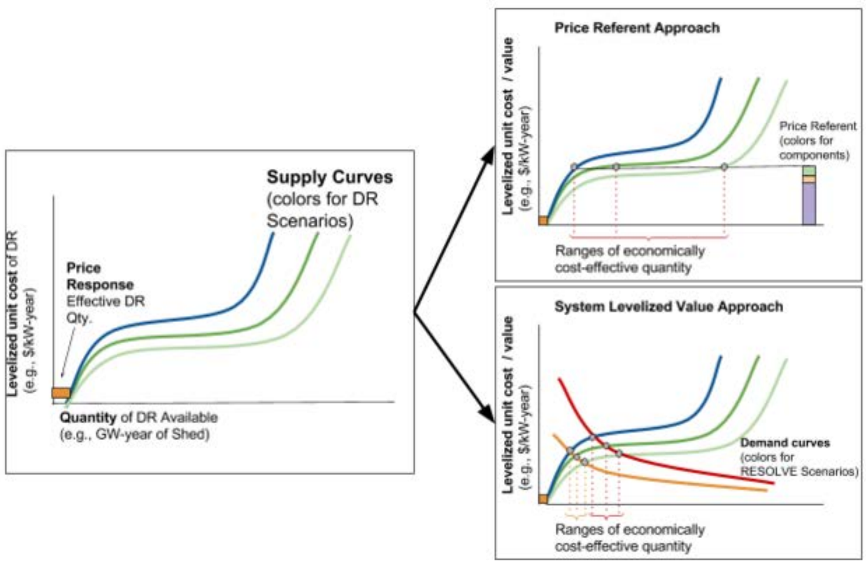

Figure 1: Illustrative diagram showing two approaches for DR economic valuation used in this study: Price Referent and System Levelized Value.

1.3. DR Services to the Grid

We find that there are many opportunities for flexible loads to provide value to the operation of a renewable powered electricity system.

The **Shape** resource provided by Time of Use (TOU) and Critical Peak Pricing (CPP) can be modeled as both Shed and Shift DR service types since price signals can reduce load during peak hours, as well as shift load to off-peak hours. In this study, we assessed three TOU/CPP rate scenarios in addition to a flat rate scenario as a counterfactual baseline. Our Shape analysis is based on a model developed by Nexant to estimate of how retail pricing structure is expected to change load, based on empirical data from pilots and past performance. We model three of many possible mixes of TOU/CPP rate adoption (Rate Mix #1, #2 and #3), which are described in more detail in the main report. In Figure 2 below, the x-axis indicates total GW of Shed DR

provided by various TOU/CPP rate mixes. Shape-as-Shed DR resource is calculated by taking the price response load impacts from the top 250 hours. In summary: For the Residential sector, all of the Rate Mixes have a default conventional TOU rate and ability for customers to opt-out to a flat rate. We integrate the expected load impacts from each Rate Mix and translate them into magnitudes of effective Shed and Shift service. Shape-as-Shed service is estimated by treating reshaped loads as if they were dispatched to meet system needs, and finding the equivalent quantity of load Shed.

The results from the Shape-as-Shed analysis show a total effective Shed for each of the three options at approximately 1 GW. Rate Mix #1 and Rate Mix #3 have no CPP for residential customers (but are included for non-residential) and different mixes of TOU rates (#1 includes "super off-peak" rates). Rate Mix #2 has a TOU mix similar to Rate Mix #3 but also includes a residential opt-in CPP option. The Shape-as-Shift DR potential is approximately 1.8 gigawatt-hours (GWh) per day for 2025, indicating that significant load can be shifted throughout the day with price signals from retail rates. The average total daily load in 2025 is 600–700 GWh, so the Shape-Shift resource represents approximately 0.3 percent of load shifted.

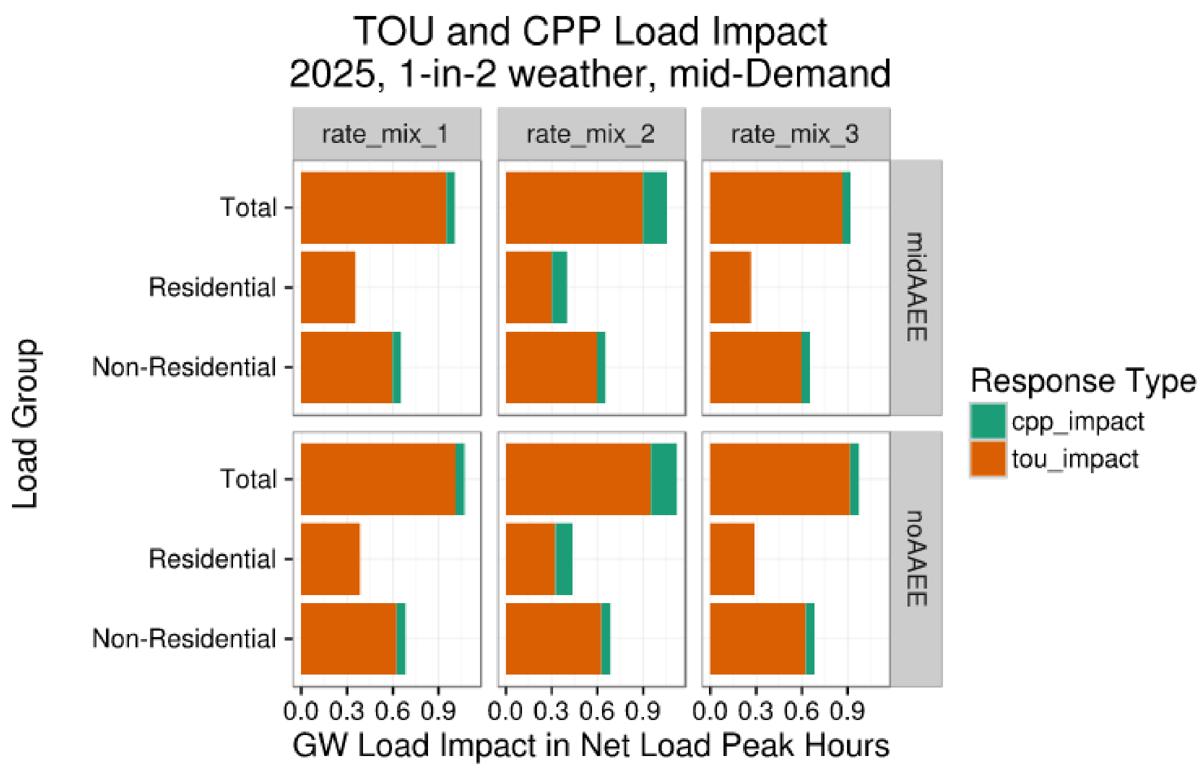

Figure 2: Shape-as-Shed resource for 2025 under 3 rate mixes under the 2 energy efficiency (EE) scenarios: no AAEE and mid-AAEE.

We modeled Shift-type DR resources that consume load and shed load during a 24-hour period,

remain energy neutral, and are based on end-uses that can move energy consumption from one hour to a different hour. Shift-capable loads have significant potential to reduce overgeneration during hours of high renewable generation and avoid the need for some multi-hour ramping.

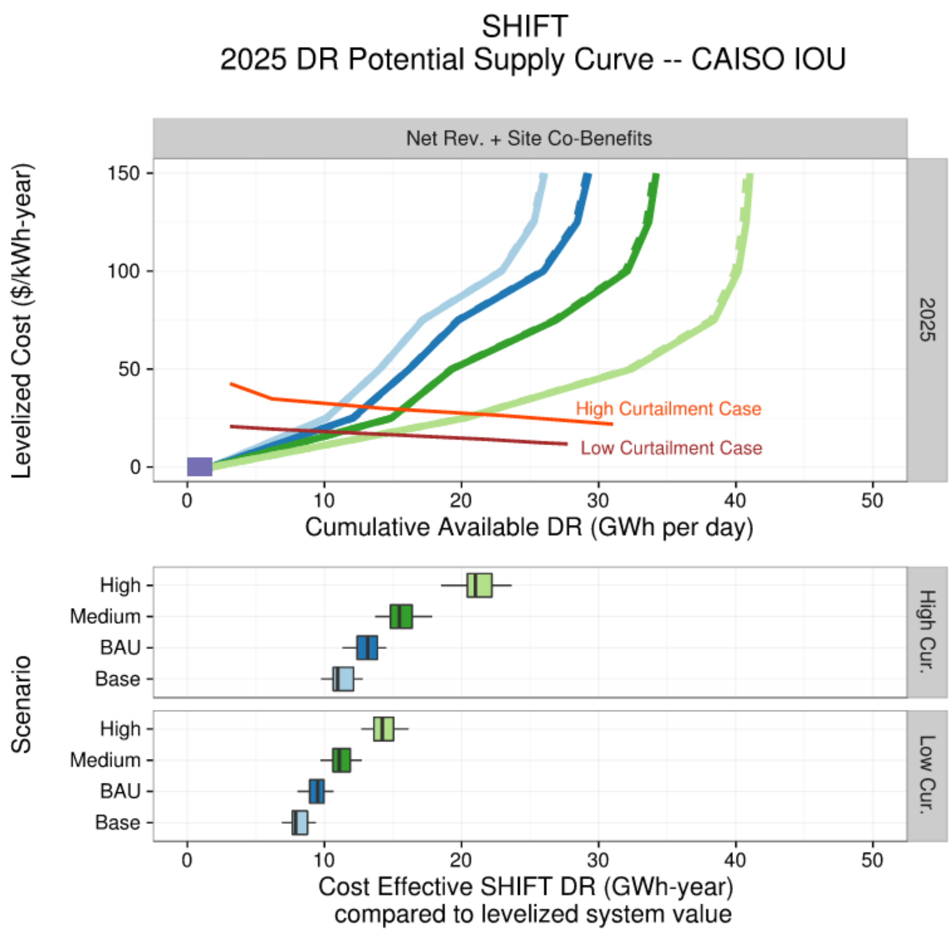

Figure 3: (top) Shift DR supply curve compared to demand curve, and (bottom) range of cost-effective quantity from Monte Carlo analysis.

Figure 3 shows the breakdown of the Shift DR potential in 2025 at the $50 price ceiling, disaggregated by utility service territory and end use. Colors (**top**) and bars (**bottom**) represent DR market scenarios. Dotted lines are 1-in-2 weather and solid are 1-in-10 weather. Low- (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines are demand curves. Equilibrium price is the intersection of demand curves and supply curves. Industrial loads provide approximately 4 GWh-year in PG&E, and nearly 5 GWh-year in SCE, with agricultural pumping providing 1.7 GWh-year and 0.5 GWh-year in PG&E and SCE, respectively. Commercial HVAC is another large contributor, with more than 5 GWh-year between the three IOUs.

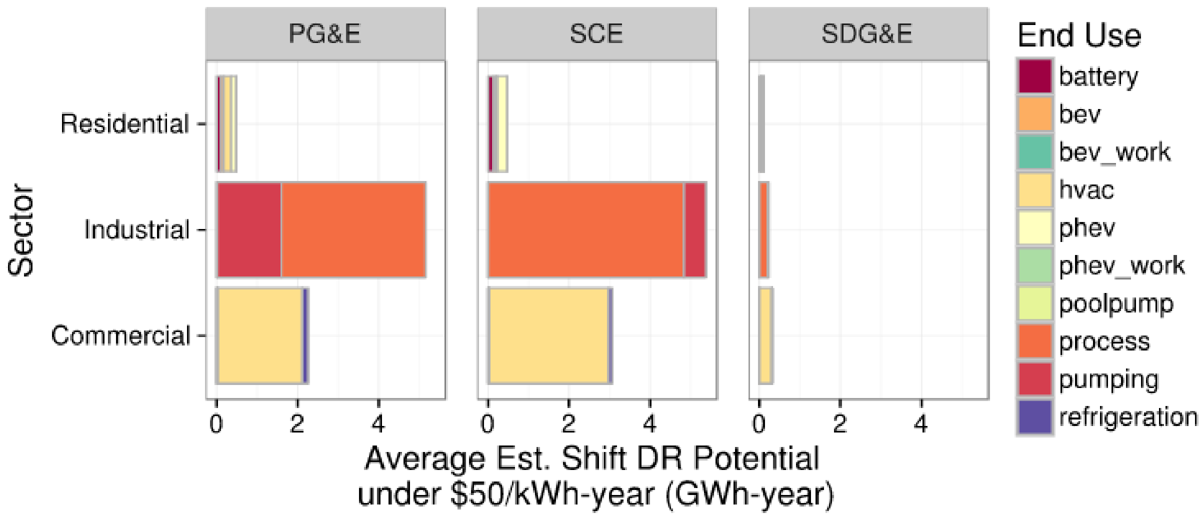

Figure 4: 2025 Shift DR potential by IOU service territory and end-use contributions under $50/kWh-year, mid-AAEE, 1-in-2 weather year, medium scenario.

ISO market integration challenges: Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration, but there are significant market and regulatory challenges for capturing this value through centralized dispatchable markets. These include challenges establishing a baseline for frequently-dispatched resources like Shift, organizing and coordinating resources for discrete dispatch, ensuring CAISO market software reflects the capabilities and operating constraints of resources and identifying mechanisms to compensate resources for avoided flexible generation procurement that may not be reflected in energy market prices.

Shift and Price-based Dispatch: Energy market prices are an indicator of what Shift patterns are most valuable—increasing demand when there is s surplus in renewable power (at zero marginal cost) and reducing loads in the early morning and evening when prices are high, and it would be appropriate to also explore how *Shift*-type resources can be handled directly in the retail market through pricing programs paired with automatically responsive DR controls. The retail price framework for organizing shift could accomplish the same fundamental dynamics as wholesale market integration but with much more transparent and simple "dispatch" –simply connecting consumption of electricity by particular loads to the forecasted locational marginal price. Automated retail price response would avoid some transactions costs related to scheduling coordinators, eliminate issues related to estimating counterfactual baselines, and eliminate constraints introduced by ISO market dispatch integration. A retail-based Shift pathway would also come with its own challenges around incentivizing investment in control technology and customer adoption, compared to the wholesale market case where DR aggregators have strong incentives to understand how to best target technology investment at customer sites.

Regardless of whether **Shifts** are dispatched directly through wholesale markets or indirectly through predictable and/or automated price response, there is a significant potential to provide value to the grid if DR technology and systems are installed and available for response. The current stock of conventional DR technology is fast enough to respond to the necessary signals and may be candidates for parallel use or low-cost upgrades compared to new DR sites with updates to control routines and settings. Current work on integrating control technology in the energy code should adapt to ensure that Shift capabilities are achieved along with conventional Shed.

Conventional **Shed** DR is procured and dispatched to decrease system-wide load during peak day events, designed to offset the need for operating peaking power plants, reduce pressure to invest in conventional generation to carry the peak load and respond to contingency events. The dynamics of the system needs, however, are quickly changing with respect to peak capacity planning.

Under a "conventional system peak DR" price referent cost-effectiveness framework, our findings suggest that Shed DR resources could provide ~4.2 GW of RA credit capacity in 2025 under the 1-in-2 weather, mid-AAEE, Rate Mix #3 scenario utilizing the price referent of $200/kW-yr. Even more would be possible if site level co-benefits are captured, which is shown in Figure 5**.** Colors lines (**top**) and bars (**bottom**) are DR market scenarios. Dotted lines represent 1-in-2 weather, and solid are 1-in-10 weather. $200 price referent is generation (**PURPLE**), transmission (**ORANGE**), and distribution (**GREEN**). The Shape-shed DR results are additive and provide an additional 1 GW of reduction (labeled "TOU/CPP"), for a total of 5.2 GW.

A second economic assessment methodology, a system levelized value approach using RESOLVE to generate system *demand* curves, results in different conclusions about the economically cost-effective amount of **Shed** DR –essentially suggesting that there is close to zero value created related to avoiding investment in the generation fleet. The outcome is the result of rapid deployment of renewable generation before significant retirement in the thermal generation fleet. Combined with significant energy efficiency investments that modify the system load curve, the expectation is that there will typically be sufficient generation available during net load peak times to meet system-wide demand, and therefore no opportunity for accounting for value from avoided investment in new capacity, (i.e. the avoided cost of a CT generation plant).

There are still significant opportunities for Shed DR to provide value to the grid that are not explicitly modeled in RESOLVE. First is local capacity. While there is a surplus on the system level, the local availability of generation is still a binding planning constraint in some transmission-constrained areas. The Los Angeles Basin, San Diego, and Ventura County all currently experience local capacity constraints that must be met either with costly local

generators (with attendant emissions in densely populated areas), fixed energy storage, or demand response and other IDSM approaches. A conventional price referent may be appropriate for estimating the local capacity resource value, or a more in-depth geographic analysis of DR potential and the cost of alternatives. About half of the statewide Shed resource (2–7 GW depending on the scenario) is located in these currently constrained areas. Second, fast **Shed** resources have the ability to meet the needs of the distribution system and avoid investment and maintenance. Finally, there may be a role for DR to respond to contingency events that are not avoided through normal resource adequacy planning processes, preventing or limiting the extent of blackout. These “Emergency DR” services have highly uncertain potential due to uncertainty in both the effectiveness of DR for mitigating cascading failure events and the value of avoided blackouts.

For 2025, we modeled significant renewable capacity contributing to the system's supply. The RESOLVE model indicates slightly more economic opportunities for the utilization of conventional DR, namely meeting ramping needs. As customer-sited solar becomes a larger contributor to mid-day electricity supply, other generators must be ramped down to prevent curtailment. However, the sun goes down as the evening demand peak sets in, creating a need to rapidly ramp-up non-solar generators back to meet evening load. In the absence of DR, this need is met in the RESOLVE cases by a combination of increased California gas dispatch, higher imports, and energy storage discharge. When Shed DR is available, it is frequently dispatched by RESOLVE during these steep evening ramps. However, the low value for Shed resources even in 2025 and 2030 suggests that RESOLVE does not find significant value for Shed resources in reducing renewable curtailment due to alleviating upward ramping constraints in the 2016 - 2030 timeframe. Rather, the value that Shed DR provides in dispatch is related to fuel savings from reduced gas dispatch. This value is relatively small, even during the peak periods.

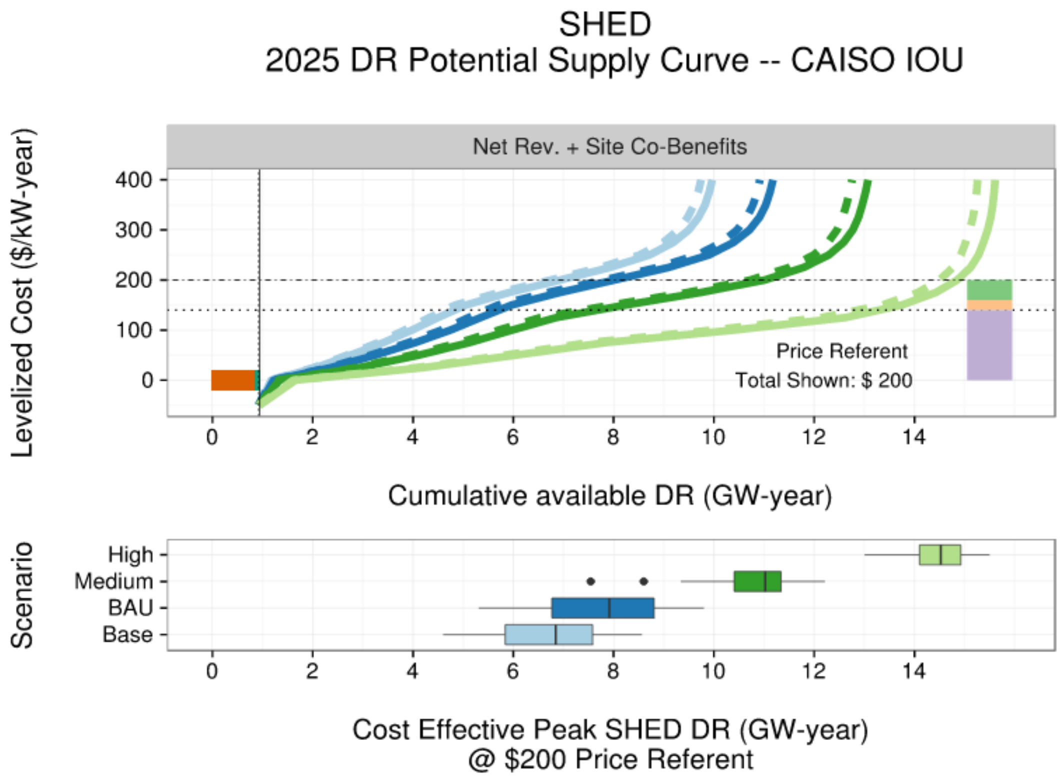

Figure 5: (top) Shed DR supply curve compared to conventional $200/kW-yr price referent, and (bottom) range of cost-effective DR based on Monte Carlo analysis of DR market and technology.

Shed DR technology is diverse and quickly evolving as more end-uses become enabled with control technologies. We provide the 2025 Shed DR results broken out by utility, sector, and end use. In PG&E approximately 1.5 GW of the 3 GW of Shed potential comes from the industrial sector, while ~800 MW comes from commercial and ~600 MW from residential sectors. SCE's potential is driven equally by commercial and industrial, with approximately 1.25 GW from each sector, and another 0.4 GW from the residential sector. In SDG&E, commercial sector lighting and HVAC are key end uses that provide the majority of the available Shed DR.

The **Shimmy** service type is fast DR that operates on a seconds-to-minutes ("regulation") and minutes-to-hours ("load following") timescale that has high value for managing short-term fluctuations in the net load.

We estimated that Shimmy resources have the potential to provide value to the CAISO system over the 2016–2030 timeframe. We found a total of $21 million in benefits for 600 MW of load following in 2025, and $22.5 million in benefits for 600 MW of regulation in 2025. Just as the savings offered by Shift resources decline as the system becomes saturated with available Shift resource, the savings per megawatt of Shimmy fall as we add more Shimmy resources. We also found that 600 MW is close to the market depth for regulation, whereas the market for load

following is deeper. Results from the RESOLVE model suggest a core value of Shimmy resources to grid operation in the future could derive from freeing battery storage to prioritize soaking up cheap renewable power instead of managing short-run variability—essentially freeing the batteries to provide additional Shift resource.

Our results indicate that **Shimmy** load following resources are cost competitive for ~350 MW at about $50/kW-yr. **Shimmy** regulation DR is shown to be cost-competitive up to approximately $85/kW-year in the medium scenario, resulting in a DR potential of ~450 MW across all three IOUs. As more DR is added, it becomes less valuable, resulting in a cost-competitive DR potential of 300 MW up to approximately $75/kW-year in the high scenario.

Shimmy resources have the potential to provide significant but bounded value to the CAISO system over the 2016–2030 timeframe—significant in having a relatively high value per kilowatt per year but bounded by the fact that the size of need (and markets for ancillary services) are finite and based on the short-term variability on the electricity system. The value of advanced DR will increase over time, as the CAISO system integrates additional renewables and curtailment becomes more significant during the midday hours.

The CAISO has been working to establish rules and transaction requirements to enable DR to more readily participate in ancillary services (AS) markets, but this has been unrealized. However, the current market prices for AS, in particular, regulation up and regulation down, are depressed, and currently, may not reflect future pricing trends for products participating in these markets in 2020 or 2025.

1.4. Transitioning from conventional to advanced DR

For years, the greatest need to the electricity grid was managing peak demand; however, with the more use of renewable generation and mandates to meet even higher RPS of 50 percent, the challenges of the grid have shifted away from peak capacity shortfalls, thus drastically reducing the need for Shed-type resources for serving the CAISO balancing authority over the coming decade and beyond. This suggests that the focus on system Sheds should be redirected to focus on local and distribution system needs and that the control technology and business relationships in place could be the foundation of new portfolios that combine targeted and/or fast Shed with Shift. Achieving these transitions will likely require the following:

- Integration between policy at the CPUC and CAISO to ensure that market designs are matched with the most cost-effective pathways for DR services.
- Continued work on how integrated energy efficiency (EE), behind-the-meter storage and DR can lead to value across a range of categories—integrated demand-side management.
- Continued work to integrate value streams at the system scale, on the distribution system, and at the site level—distributed resource planning (DRP). We did not undertake

a detailed study on site-level electric bill impact or explicit distribution system service modeling dynamics but did include a set of first-order estimates for the scale of benefits in these areas that are likely achievable when DR technology provides multi-scale service. Given the co-benefits for site-level service, the result is an increase of about **4 GW of additional Shed DR** capacity compared to a model run without co-benefits.

2. Introduction

Demand response is an important resource for keeping the electricity grid stable and efficient; deferring upgrades to generation, transmission and distribution systems; and providing other customer economic benefits. The CPUC in looking to meet California's rapidly evolving resource planning and electricity grid operational needs is evaluating how to *significantly enhance DR's role*. Although California has extensive experience with certain forms of DR, new and different DR resources will be required for the grid's evolving needs - ones that are more flexible and able to respond faster than their historical counterparts.

The CPUC recently bifurcated the investor-owned utility DR program portfolio into two categories: (1) load-modifying resources, which reshape or reduce the net load curve; and (2) supply resources, which are integrated into the CAISO energy markets (CPUC Decision D.14-03-026). The definitions and operational requirements for each will have important implications for whether feasible DR options can participate and provide value across a range of grid services. The CPUC's decision provides a general framework for the future of DR in California.

Our study used advanced metering, customer demographics, technology and other data to estimate how DR can cost-effectively meet the needs of California's changing electric grid. This report details how DR can meet the system and local peak capacity needs that drive California's resource adequacy (RA) requirements and how advanced technology can enable fast-response DR and help meet California's need for future capacity and ancillary services.

The geographic scope of our study was the service areas of the three major California IOUs: Pacific Gas and Electric Company, Southern California Edison and San Diego Gas & Electric. We worked with staff from each organization to obtain customer electric load data to support this work. A broad stakeholder group contributed technical expertise to inform our study. This technical advisory group (TAG) includes representatives from the utilities, DR aggregators, regulatory agencies, advocacy organizations, and others who provided important input that informed our approach and methods. We have developed a framework for characterizing the cost, performance, and availability of manual and dispatchable DR technology.

In the future, California's power system will include larger fractions of energy provided by wind and solar energy, an increase in new loads such as electric vehicles (EVs), and the potential for greater availability of dedicated energy storage. There have also been dramatic increases in the capabilities of "Smart Grid" information technology systems, with high-resolution visibility and control and new analytic and operational capabilities. Our study's foundational goal was to identify "system needs" and new ways that DR's technical capabilities can meet those needs (***Figure 6***). We compared DR to alternative approaches such as traditional AS from generators, grid infrastructure expansion and grid-scaled dedicated energy storage technology. Additionally, we took into account realistic customer preferences and market dynamics.

Although California has extensive experience with certain forms of DR, new and different DR resources will be required for the grid's evolving needs - ones that are more flexible and able to respond faster than their historical counterparts.

For four DR services types in this analysis, LBNL created a structure that generates levelized cost supply curves and demand curves in 2020 and 2025. The supply curve framework was based on a bottom-up, customer end-use load forecasting model based on more than 200,000 interval and smart meter load shapes. We developed granular load flexibility potential estimates using end use forecasts. LBNL then combined these potential estimates with a detailed DR cost database to express DR supply curves for different grid services, which estimated how much DR is available across a range of levelized costs.

2.1. Regulatory and Technology Background

The CPUC Energy Division funded this study to support DR policymaking, concurrent with rulemaking R.13-09-011. Based on the current policymaking process needs, we estimated how DR could provide grid services in 2020 and 2025, across a range of scenarios for DR market and technology options. This report summarizes our results after the second of two project phases.

In Phase 1, we studied conventional DR (peak load shedding resources that qualify for system and local resource adequacy capacity credit) and compared the cost of DR with an estimate of the avoided cost for conventional generation, transmission, and distribution. This phase included Shed and Shape-as-Shed DR. We released Interim Phase 1 findings on April 1, 2016. The findings were updated on August 19, 2016 with improved assumptions. Concurrent with the update, the software and data inputs developed for Phase 1 were released publicly under an open source license.[1]

In Phase 2, we broadened our study to cover more advanced technology options that can enable fast-response DR and can help meet California's future capacity, energy, and ancillary service needs, including the full stack of DR types we outline above (Shape, Shift, Shed, Shimmy). While the underlying approach is the same as Phase 1 (comparing the cost of supplying DR resources to an estimate of the value for those resources), it also introduced substantial methodological advances. First, is the use of a system optimization modeling approach to estimate the service value rather than a static price referent. The LBNL team selected the RESOLVE model, executed in collaboration with E3, because of the modeling framework flexibility for adding DR capabilities that match with the LBNL-LOAD and DR-PATH estimates. An additional improvement in Phase 2, is using a "Monte Carlo" analysis to estimate the uncertainty in forecasts for DR potential.

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[1] Available at: http://drrc.lbl.gov/project/2015-california-study

This study focuses primarily on system-level services (i.e., services that meet needs at the transmission system level and could be organized by the California Independent System Operator, or CAISO) to help inform the process of "bifurcation" in demand response. Bifurcation is an organizing concept for advancing DR policy. It refers to integrating some resources into the CAISO markets for direct dispatch to meet system needs (known as "supply" DR) with other resources that are controlled or dispatched outside the market (known as "load-modifying" DR). While we focus on system-level dynamics, we also include estimates for the way DR technology could help needs at the local sub-transmission level and local capacity areas (LCAs). These layers of value help provide context to the system-level estimates and could be part of future portfolios of jointly planned resources that meet electricity system needs for both the distribution and transmission systems.

2.1.1. The Need for Flexible Loads on the Electricity Grid

California's electricity system is undergoing unprecedented change. Long a leader in environmental policy and renewable energy development, California's current goals call for meeting 50 percent of California's retail electricity sales with renewable energy by 2030 and reducing greenhouse gas (GHG) emissions to 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. In addition, California policies are expected to result in significant adoption of behind-the-meter solar PV. The implications for managing a substantially cleaner electricity system are what drive our framework for understanding the role of DR in the future grid.

A 50 percent renewable electricity system in California will have high penetrations of variable solar and wind generation, collectively reaching as high as 35 to 40 percent of total delivered electricity by 2030. Variable generation is different from conventional generation because it can generate electricity only when the wind and solar resources are available. Moreover, the output of wind and solar farms are subject to both variability and uncertainty, meaning that the output fluctuates from moment to moment in a manner that is not entirely predictable.

This rapid scale-up of renewable generation combined with aggressive energy efficiency investments in California is leading to a fundamental shift in generation planning for the grid. The now-famous duck curve illustrates how the net load profile that needs to be carried by conventional and dispatchable generation has changed, with a significant reduction in the overall peak and a shift in the net peak from mid-day to the early and late evening hours.

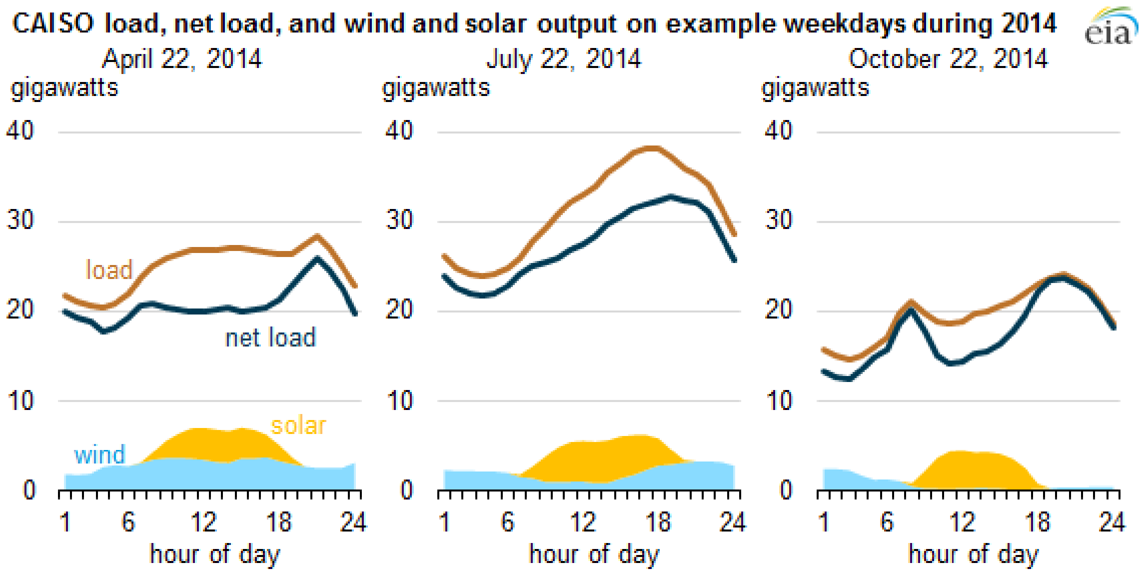


Figure 6: Changing system needs in California for ramping to meet net load have been described as a "duck" curve because of the graph's shape (here, most evident in the net load curve from October 2014). Source: Based on CAISO data and CAISO / EIA reports.

Peak loads continue to grow, but more slowly than they had historically. Based on our best estimates of plant retirement schedules, the conventional fleet that was has been developed as part of long-run reliability planning is now sufficient for meeting system-level peak demand into the near future, through 2025. Thus the value of DR that is targeted for reducing system-level peaks is diminished compared to the case where it captures both operational revenue from energy markets and offsetting generation capacity investments. While the apparent value of system-level Shed resources is low, the ability to Shed to support local reliability in transmission-constrained areas and constrained distribution circuits remains important and valuable, and as we describe below the need for system-wide Shed has been replaced with the need for Shifts, which could provide significant renewables integration value.

Figure 7 below illustrates grid conditions for on Summer Weekdays, which continues to be the annual peak load season. The rows show gross load statistics, the net load (gross minus intermittent renewables), and the contribution of intermittent renewable power generation (solar and wind). For each type of trend line, the left column shows the average of all summer weekdays, and the right column shows the maximum observed value for each hour of the day. These data show the "mid-AAEE" energy efficiency scenario and "Rate Mix #2". The growth in peak gross load will be slowed by energy efficiency, and the contributions of wind and solar both reduce the peak load and shift the annual peak hours into the evening (from ~2 PM to 7 PM). Figure 8 zooms in on the annual peak net loads and the overall effect we observe in the years we simulated is that the trend from 2015-2025 has relatively slow growth in the net load peak, from 42 to 46 GW over the period (based on the 1 in 10 weather scenario). The colors represent different rate mixes and the line type represents different weather scenarios. The data

shown are for the 'mid-AAEE' energy efficiency scenario. The existing and expected future generation fleet has been planned over multi-year reliability study periods for a higher peak load.

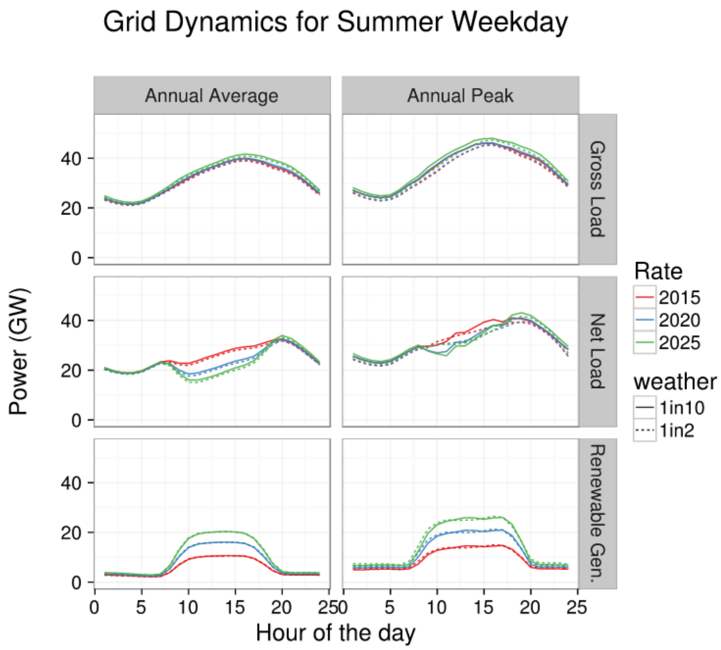


Figure 7: Grid conditions on for Summer Weekdays, with trends grouped by year (color of line) and weather scenario (line type).

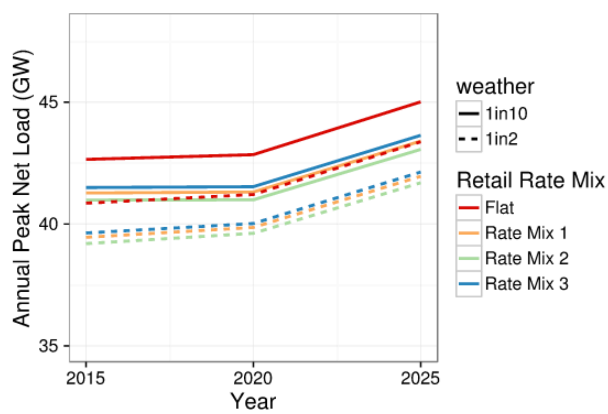


Figure 8: The annual peak net load across the three study years.

In the study, we identified the resource with the highest potential annual grid value, which was a Shift to capture excess renewable energy and reduce the cost of operations. Figure 9 below, exemplifies the need, showing the Shift resource dispatch profiles we estimated with RESOLVE mapped onto the annual load forecast for a 2025, 1-in-2 weather scenario. In Figure 9**,** estimated optimal dispatch profiles are shown in figure (A) from a load perspective, whether the load goes

up or down, and in figure (B) from a generator perspective, as if the load was bidding into the energy market. The dispatch profiles are averages of the dispatch profiles for the RESOLVE day types that most closely match the 365 days in our LBNL-LOAD model year. This represents the times when it is valuable to shed and to take, given the flexibility to shift throughout the day. There is a significant and distinct expected need to "take" energy in the middle of the day and "shed" in the early evening. In the late night and early morning, a mix of shed and take is optimal, depending on the day. From the generator perspective, this looks like "Generator Up" for shed and "Generator Down" for "take" – and the graphical representation recreates the Duck Curve. This essentially confirms that the value that can be created from Shift DR derives directly from renewables integration energy capture.

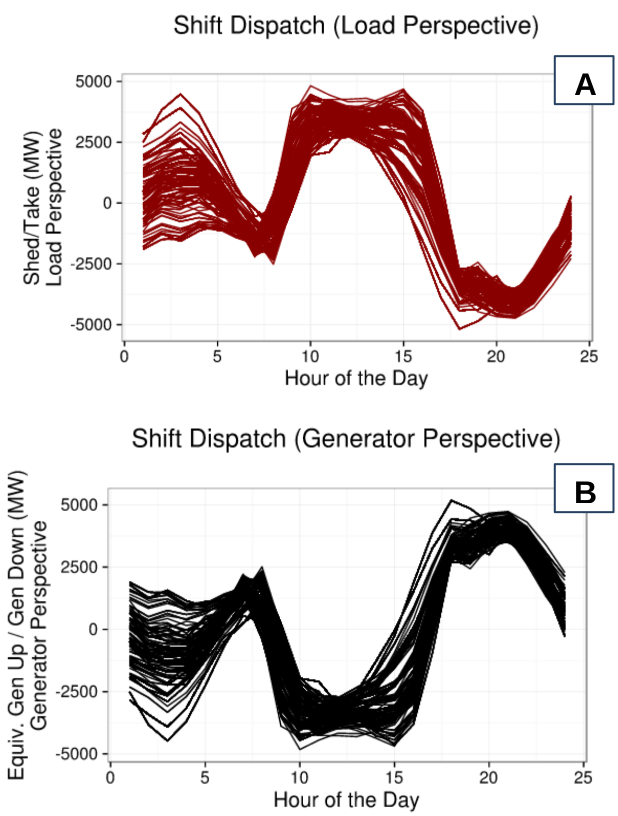


Figure 9: Estimated optimal dispatch profiles for Shift resources from two measurement perspectives.

2.1.2. How DR Fits into CPUC Goals and Other Proceedings

The transition to bifurcating DR is occurring in the context of other important and related policymaking efforts at the CPUC and California Energy Commission (CEC).

Loading order: In 2003, the principal energy agencies in California established a loading order, putting as high priorities energy efficiency (EE), DR, renewables, and distributed generation. This order effectively prioritized decreasing electricity demand before developing more

generation, and using renewable and distributed generation before fossil-fueled generation. In 2012, the CPUC reinforced the loading order with a ruling that standardized the planning assumptions across all three IOUs. The CPUC noted an ongoing preference for DR and EE by explicitly noting, “The loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved.”

Planning processes: Three important planning processes could incorporate DR and assist in replacing, or delaying the need for investment in, alternatives to meet the requirements for a reliable and efficient grid: resource adequacy (RA) planning, the long-term procurement plan (LTPP), and the transmission planning process (TPP). These are summarized below:

- RA: In 2004, the CPUC adopted an RA policy framework establishing RA obligations for all load-serving entities (LSEs) within its jurisdiction. The intent is to demonstrate that each LSE has procured sufficient capacity resources, including reserves, to serve its aggregate system load and local reliability needs on a monthly basis. Each LSE must show RA that is sufficient to meet 115 percent of its total forecasted load.
- LTPP: LTPP by LSEs is a 10-year look-ahead at system, local, and flexible needs, comparing anticipated demand against existing generation and new resources, and excluding retirements.
- TPP: CAISO’s TPP is an annual planning process to direct investment in transmission system additions and upgrades in support of a range of system goals.

Valuing DR: The ability to count DR towards RA and the manner in which DR is incorporated in long-term planning are critically important for establishing value streams that incentivize investments in DR technology, programs, marketing, and incentives. A set of DR working groups was convened to guide the joint parties Joint Proposal (in CPUC Rulemaking R.13-09-011), with work on load-modifying DR, supply resources, and a DR auction mechanism (DRAM). These working groups’ reports and outcomes inform the current study’s inputs and assumptions.

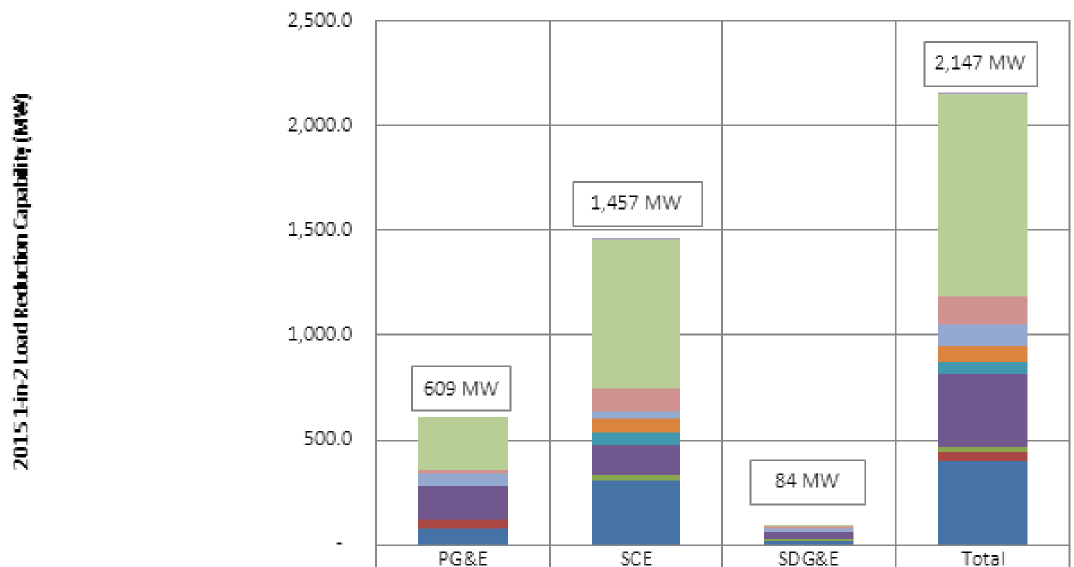
On December 9, 2014, the CPUC issued Decision (D.) 14-12-024. Most important to our study, this CPUC decision approved and outlined a study to assess the DR potential in the service territories of California’s three largest utilities: PG&E, SDG&E, and SCE.

In its 2014 decision, the CPUC established a four-year timeline to assess the potential for DR, during which working groups are to create recommendations for categorization and valuation of DR programs. On November 19, 2015, the CPUC issued Decision 15-11-042, which clarified the commission intent to proceed with bifurcation and defined the pathways for valuation of supply and load-modifying resources (specifically that load-modifying resources only provide capacity value through being embedded in CEC load forecasts that are used to set procurement targets). The CPUC is set to enforce this strict bifurcation as of 2018. The decision also

approved a set of updates to the cost-effectiveness protocols used to evaluate utility DR activity. Our study incorporates both DR resource categories (supply and load-modifying) in a harmonized framework to help inform the continued development of DR markets and programs.

2.1.3. Existing DR in California

Figure 10 shows the existing DR capability by IOU and customer sector in California for 2015. These data show that the IOUs currently provide about 2.1 GW of DR according to the administrative and market settlement frameworks for defining the size of the resource. In the Results section of this report, we comment on how these values compare with the DR in the LBNL model for 2014, which is an important benchmark comparison for our model.



	PG&E	SCE	SDG&E	Total
Non-Res - Real time pricing		2.5		2.5
Non-Res - Interruptible rates	252.1	707.8	1.0	961.0
Non-Res - Demand bidding	21.0	114.5	2.6	138.1
Non-Res - Critical peak pricing	51.5	29.8	20.9	102.2
Non-Res - Air conditioner load control	2.7	64.3	3.1	70.1
Non-Res - Agricultural pump control		59.4		59.4
Non-Res - Aggregator programs	165.7	147.2	34.7	347.6
Residential - Peak time rebates		27.0	5.3	32.3
Residential - Critical peak pricing	36.9			36.9
Residential - Air conditioner load control	78.9	304.5	17.0	400.3

Source: Utility Monthly reports on interruptible load and demand response programs. Filed with the CPUC (A.11-03-001).

Figure 10: Total DR resource based on filings for 2015.

2.1.4. New Approach for DR Potential Estimation

This research is the first study to comprehensively evaluate the technical potential, availability and cost-competitive potential of DR in California, and presents a new methodological approach for public policy support of the electric power system. We have organized and integrated new DR economic and market value concepts, and use newly available Advanced Metering Infrastructure (AMI) data as a basis for modeling DR potential. California has a strong history of conducting related research on the potential for energy efficiency. This research will extend this tradition into the DR realm, but with significant changes to the approach and methodology.

Our team developed a framework that creates supply curves of enabling technologies and end-uses for the DR products in order to determine the potential DR in California. Rather than following the EE framework that looks at the annual technical, market, and economic value streams, this new approach allowed us to examine DR availability on an hourly basis, using hourly load profile customer data, and end-use load profiles to determine the amount of DR available for each hour of the year. Because the value of DR is based on the hourly availability, this methodology gave us the ability to determine how much supply is available for each hour and weight its value based on overlap with times of system need for specific DR products. For our study, we did away with the references to technical, market and economic potential, and rather, introduced the following:

- **End-use Load Forecasts and Technical Baselines:** Segmentation, disaggregation and forecasts of end uses over a range of customer clusters that represent the population and building stock. These establish the expected baseline gross load disaggregated by end use across a diverse building stock.
- **Supply Curves of DR Potential:** Development supply curves that synthesize the DR costs, availability, shed-ability and quantity coincident with system net load needs.
- **Economic Valuation of Cost-competitive DR:** Determination of the value that DR could provide compared to alternative sources of reliability and capacity. The competitive quantity of DR is based on analysis of the supply curve in the context of the alternative technology price.

The model we used to implement the study is organized in two main modules. The first, LBNL-LOAD, is an end-use load, baseline-forecasting engine. Taking raw data from utility databases in combination with supporting datasets, we create forecasts of large representative sets of end-use load shapes over the course of a year, with hourly resolution (8760 hours per year). These fundamental baseline load shapes are the key input to DR-PATH, our techno-economic model for demand response.

The key features of LBNL-LOAD are:

- **Clustering** the customers in the state into representative demographic and energy usage groups speeds the computation and is appropriate for large-scale geographic potential modeling. Our approximately 3,500 clusters represent the customers in the services territories of PG&E, SCE and SDGE.
- **End-use baseline load shapes** are disaggregated based on weather sensitivity and first-order engineering models.
- **Linked renewable generation and weather** modeling lets us use weather-adjusted baselines that are linked with a coincident renewable generation potential forecast to estimate DR Potential. This means our estimates are in the context of a plausible net load profile that can be the basis for valuing the timing of demand-side resources.
- **Harmonization** with existing policy frameworks is important to make the model useful for planning, and we link the forecasts for growth in demand and investment in energy efficiency to CEC long-term forecasts.

The key features of DR-PATH are:

- **Cost and performance data** for a range of DR technology options are used to define the inputs to a techno-economic model, which uses the baselines from LBNL-LOAD to estimate availability and technology cost resources at sites where they are installed.
- **Propensity score models** define the likelihood of customer adoption, which we use to estimate the effects of customer engagement, marketing, and incentives on DR resources potential.
- **Supply curves** for DR resources are based on a well-defined taxonomy of resource types, and enable transparent comparisons of the cost and performance of DR to its value or other investment options for supporting the grid.
- **Monte Carlo** analysis lets us simulate many possible future pathways for the system and reveal the inherent uncertainty in forecast estimates. The architecture of the model enables computational parallelization (which speeds up the code).

Comparing DR to EE

One of the challenges of estimating DR's potential in a framework that is useful for planning and policy development is the manner that DR differs from energy efficiency, with regard to measure lifetimes and "durability." Specifically, in efficiency potential studies, each efficiency measure has an assumed lifetime during which it provides a relatively predictable stream of energy benefits from fixed equipment under regular operation. DR products, however, involve a set of strategies and actions taken by customers, or automatically by devices, in response to a system event or signal. These dispatch events may occur frequently or rarely depending on how particular sites participate in day-ahead and real-time electricity and ancillary services markets managed by the CAISO. This temporal variance in DR provision of grid services makes it vastly

different from energy efficiency analyses. There are also differences in the durability of resources from year to year. Energy efficiency load reductions last for the full useful lifetime of equipment, while customer commitments to load curtailment are often renewed on a periodic basis (e.g., annually). Therefore, with respect to “measure lifetimes,” DR technology attrition includes control equipment failure along with enrollment-related factors like the opt-out rate and effects of move-outs. In the model we developed, we employ an estimated lifetime for automation technology to characterize the investment horizon for controls in developing DR levelized costs that includes our best estimate of these combined effects.

This study’s approach deviates from energy-efficiency potential studies in several ways. As discussed above, DR measure lifetimes often differ from energy-efficiency (EE) measures, where an end use can be installed in a site and the savings begin accruing as soon as the end use becomes operational. Many EE programs have incentives that are paid through upstream, midstream, or downstream payments. For DR technologies, few of these characteristics apply. Rather, customers are recruited and offered the program via customer account managers, aggregator outreach, direct mail, phone calls, and in some cases, door-to-door. The DR programs typically have constraints on how often the program will be dispatched, and the customer load availability (i.e., whether the end use in operation) is uncertain. If the DR program requires automation for signal and dispatch, then installation and provisioning of the technology adds another complexity layer that is not involved with EE end uses.

A growing number of integrated demand-side management measures provide both EE and DR capabilities; these include smart communicating thermostats or advanced lighting controls or building automation systems associated with space conditioning that enable DR communication.

In EE programs, a utility can commit to a buydown of specific end uses by their make and model, which are clearly defined by ENERGY STAR standards. Policy at both the state and federal level provides guidance on building codes, lighting and appliance standards that facilitate adoption of EE technologies. The framework for DR programs and standards is not as well defined. DR enabling technologies, dispatch requirements, qualifying loads and program rules lack the standardization that EE maintains.

Additionally, because of bifurcation, DR is increasingly seen as a distributed energy resource (DER) that needs to have the flexibility for dispatch across a number of hours throughout the year. However, DR benefit streams are unequal during all hours, and the resource isn’t always available at all times since the program administrators typically constrain the number of events that will be called to increase program participation. End uses such as HVAC units that are enrolled in the programs are not typically running year round or at all hours. These factors complicate how to assess DR value and available quantity throughout the year. We note this is an area where the state-of-the-art for EE programs is advancing as well; the same advanced meter data that supports our study can also improve EE benefits’ estimates.

2.1.5. Extending the analytic framework

Our analytic framework links measured site-level loads, weather, renewable generation, and a model for estimating the implications of distributed energy investment. The organizing principle is to simulate many internally consistent cases for yearlong operation, avoiding the pitfalls of approaches that decouple the dynamics of loads, generation and behavior. Our integrated demand-side modeling framework, with appropriate modifications and setup, could be applied as well for a range of other policy and operational goals:

Informing Public Policy

Adding sub-modules to the DR-PATH and valuation elements of our work could enable testing integrated portfolios of distributed energy technology investment options, linking **energy efficiency** and **distributed generation** with demand response and fixed storage.

Establish distributed energy **technology development targets** by estimating the likely implications of technology systems with particular combinations of cost and performance. Possible future technology systems that are structurally likely to be cost-effective but do not exist in the market would be ripe for R&D, while technology options that lack feasible pathways to cost-effectiveness would not be prudent targets.

Simulate the **effect of policy decisions** with carefully constructed scenarios. An example is testing the effect of widespread code-defined control technology rollout, or testing the effect of a dynamic electricity rate paired with responsive technology.

Accelerating Smart Deployment

A key finding of our study was that there is a high value from **targeting investments in control technology and customer acquisition**--some customers have load shapes and characteristics that make the sites more likely to be cost-effective as individual opportunities. The value of DR, particularly Shed resources, is also not evenly distributed across the grid but concentrated. There are high value DR opportunities in local generation constraint pockets and in areas served by constrained distribution circuits. Using customers' AMI data and demographics to focus investment in areas potential could be applied (and ground-truthed) by using them to actively target customers with favorable demographics and loads.

With visibility into customer-level DR performance, both **controlled and natural experiments** are possible to understand how to most effectively target high value / low cost DR. This A-B test approach could help accelerate understanding of how to involve large numbers of people with DR through widespread, aggregated loads.

Catalyzing DR with AMI

California has made significant investments in Advanced Metering Infrastructure (AMI) that has led to a qualitative shift in the visibility of decentralized energy systems. With 15-minute to

hourly measurements of electricity and natural gas consumption at nearly every premises in the state, there are millions of data points being measured in the background of utility operations every day. Our analysis framework is based on a large sample of the available data (1 continuous year, 2014, for about 200,000 sites out of the total ~15 million), and shows the value of **access to large samples of AMI data** for informing public policy on distributed energy systems. It is straightforward to aggregate and/or anonymize customer data that could be used to update model inputs and assumptions.

Many non-utility actors --- aggregators, advocacy organizations, and the public sector --- are working to unlock the potential of DR, and for them to be successful in DR technology R&D and market scoping it is a priority to have some mechanism for visibility into data about the demand at the edge of the grid. We have worked with the CPUC to release an anonymized version of the underlying datasets we used in Phase 1 of this study, and they represent some of the most granular and high-resolution data that are available publicly describing California households, businesses, and industrial facilities. Ongoing and frequent packaging and release of fully anonymized site-level data could help ensure public policy is informed by an up-to-date picture of demand. With discrete, uniformly formatted, and predictable releases of data, it could be possible for stakeholders not just in DR policy but distributed resources in general to use and develop a shared set of models and tools for advocating and engaging with the public process. The data would also be a significant catalyst for technology R&D and electricity markets research. Additional work on data access for individual customers to potential third-party aggregators is likely required as well, for customer acquisition, but anonymized data could be helpful for overall market scoping and general geographic or demographic targeting.

2.2. Study Limits, Uncertainties and Simplifying Assumptions

This study provides estimates of the technical and economic DR potential in California, and is the first of its kind to implement the newly developed LBNL methodology. As is the case with any model, our framework cannot capture all the possible potential energy scenario permutations for California, and while the results are instructive, they are neither exhaustive nor a final word. The technology costs, end-use performance and adoption rates described in this report are developed to represent our best understanding of the ability of various end-uses to provide different types of DR services. More work is needed to verify, evaluate and understand these new DR capabilities in customer loads, especially the frequently dispatched and rapidly responding loads that are needed beyond the traditional DR for hot summer peak hours. This is a new field with limited data on the long-term performance of these technologies and systems. Based on the results, however, our study suggests the following potential opportunity areas for action to improve the understanding and functionality of DR in California:

- **Uncertain future value for Shed:** The Phase 2 results include findings on Shed DR under both the Price Referent valuation framework and the "System Levelized Value Approach", which is based on values from the RESOLVE model. We note elsewhere and highlight here that the ultimate choice of a "correct" valuation framework for Shed resources is complex and depends on the specifics of how resources are used. Because the RESOLVE model does not explicitly include constraints related to system emergencies, distribution system services, or local capacity needs, these are not reflected in the Levelized Value supply curves. However, the RESOLVE model is designed to accurately reflect trends in the installed generation fleet and includes constraints imposed by systemwide resource adequacy. As new approaches emerge to better model the value of contingency, distribution and local resources in a harmonized framework with system planning, we expect the results could increase for Shed DR based on an integrated Levelized Value.
- **Forecast uncertainty:** The study relies on a range of forecasts, from statewide macroeconomic trends to electric vehicle deployment. Every forecast has inherent uncertainty. As DR advances in the context of broader trends, the potential that relies on them will change as well.
- **Gathering empirical data on capabilities for building infrastructure to dynamically shift energy use.** The Shift service type resource is by far the largest opportunity we identified for DR to provide system-level value for the future grid. Significant potential value to the system (up to ~$600 million/year) from dispatchable daily energy Shifts that are enabled with advanced control technology, with economically effective DR up to ~5 percent of daily energy shifted in 2025 (for the high-curtailment, mid-additional achievable energy efficiency [AAEE] scenario), and in subsequent years, an expectation of continued growth in the valuable Shift resource quantity as more renewables come online. The model we used for estimating the quantity of technology-enabled Shift that is possible is based on engineering judgment and is not yet well-supported with field experience, which should be used to verify the resource availability and inform how to transition DR technology and markets to this emerging opportunity area.
- **Linking EE and DR "co-benefit" analysis on the integration of energy efficiency and demand response**. Customers want to be able to manage their electricity costs and have energy service options. Further understanding of how to integrate the delivery of EE and DR together will likely help lower the cost of DR. This is especially important for controls measures. Our approach to jointly consider EE and DR was through simplified "co-benefits" that did not explicitly model the dynamics of DR and EE as a portfolio of technology investment, and this first order analysis suggests large potential gains from portfolios that bridge service behind the meter with the broader grid.

- **Electric storage system sizing, control, automation and performance evaluation.** Electricity storage is a quickly evolving sector, and there is a need to better understand how the market for these systems will change in the next few years as prices continue to drop. Advanced controls for both electric storage and automated building systems are in their infancy with respect to integrating operational optimization. These systems' coevolution could significantly change the DR potential depending on the technology's trajectory, and currently, careful analysis of control systems integration and operations is needed to ensure that the systems are used in an optimal configuration.
- **Rate selection.** This study developed and implemented a methodology to evaluate how various existing and emerging Time Varying Pricing (TVP) electricity rates could provide demand reduction within the framework of DR valuation. Since these rates act as load-modifying resources that change consumers' consumption patterns, (i.e., modify the load consumption shape), they influence the amount of DR available for supply side-facing DR programs. We simulate a set of cases from 2015 TOU Pilot Advice letters, but the actual rates are likely to be different. If future rates are significantly different from those we include in the study, the underlying load shape would change.
- **Load shifting with prices.** One of the key study findings shows that there is great value from shifting electric loads to periods when there is significant potential for over generation from solar resources. Future TVP rate designs might help manage this load shifting, and this study had only limited review of this strategy. Also, the study excludes speculative analyses of how price-responsive, transactive energy devices[2] could amplify the response to time-varied prices, instead relying on existing empirical research that largely reflected behavioral modifications, structural investments in energy efficiency, and shifting the typical time of energy service.
- **Multi-market DR resources.** The supply DR resources' cost and value analysis in this study are all single DR product or market value streams. No effort was made to explore how a DR resource could provide value in multiple markets and result in a resource portfolio. This is a study shortcoming, and there are clearly issues with multiple program participation, potential complications in program baseline rules, and ultimately, the availability of DR services. A better understanding of these issues can only help improve DR cost-effectiveness measurements.
- **Distribution system value of DR**. We conducted a perfunctory and high-level, limited

[2] Transactive energy refers to the use of a combination of economic and control techniques to improve grid reliability and efficiency. For more information, see http://www.gridwiseac.org/pdfs/te_framework_report_pnnl-22946.pdf

analysis to evaluate DR's value at the local distribution system, which suggested a significant opportunity for DR, on the order of 2–5 gigawatts (GW) of responsive resource that is cost-effective. It is likely that there will be greater value for DR at the local distribution system level for constrained areas, and additionally, the value estimates from the CPUC Distributed Resource Planning (DRP) process should inform future analysis.

- **Comparison with real-world DR markets.** The Demand Response Auction Mechanism (DRAM) pilots currently**.** The Demand Response Auction Mechanism (DRAM) pilots currently underway are collecting bids from DR aggregators for Shed DR, and get a range of bids for service. These bids would be analogous to supply curves we developed for net expected revenue if the DRAM participants were bidding at their true expected shortfall (similar to marginal cost bidding, but with a longer timeframe for cost accounting). Opportunities to find additional information through market processes like DRAM can provide a valuable ground-truth for techno-economic models like the one we developed. The benchmarking we used to calibrate the model has included careful consultation with experts and Shed estimate comparisons to current-day utility programs.

3. Methodology

This section provides an overview of the study's approach, focusing on how we categorized DR resources and the mechanisms that provide value for these resources. Detailed descriptions of the methods and assumptions are documented in Appendices C–I.

3.1. DR Futures

The study's "bottom-up" modeling framework for DR capabilities and availability leverages large customer-level electricity use and demographic datasets provided by each of California's investor-owned utilities (IOUs). The first step for estimating DR resource availability is to group customers in similar cohorts, or "clusters." Each cluster represents an aggregation of real customer consumption and demographic information. Each cluster's consumption time series is disaggregating into its constituent end uses, and these end-use baseline load shapes are forecasted to the study years.

Second, the tool forecasts likely DR pathways, given existing and emerging technologies' cost projections and adoption information for the selected forecast years. The resulting pathways represent the likely set of possible futures, given technology adoption and DR product participation.

Finally, the tool presents the distilled results of the analysis through DR cost-versus-grid service product supply curves. These supply curves provide a visual representation and tool for interpreting the available DR resource in the forecasted scenarios and weather years.

In the DR Futures model, we developed two core analytical capabilities:

1. **LBNL-Load:** This is an end-use, load-forecasting approach that capitalizes on IOU-provided demographic data for the full set of more than 11 million utility customers and hourly load data for 220,000 customers across the three IOUs. Using these data, we developed approximately 3,500 representative customer clusters characterized by a typical demographic profile, location and hourly end-use load estimates. Table 1 below provides details on the number of customers and clusters by sector for each of the IOU service territories. See Appendix C for documentation, intermediate results and discussion of this model.
2. **DR-PATH:** This is a DR capability analysis model that estimates the potential hourly DR contributions to support system reliability across a diverse set of future pathways. The possible pathways consider the predicted end-use load (from LBNL-Load), technology capabilities, market design parameters, and expected participation rates-derived from the demographic variables. It includes an economic analysis framework that estimates the effective capacity available at a range of levelized cost ceilings to establish supply

availability curves. See Appendix G for documentation, intermediate results and discussion of this model.

Table 1: Customer clusters for each IOU service territory by customer sector

Utility	Customer Sector	Cluster Quantity	Average Customer Number Per Cluster
PG&E	Commercial	789	780
PG&E	Industrial	929	240
PG&E	Other	24	18,000
PG&E	Residential	320	18,000
SCE	Commercial	527	1,200
SCE	Industrial	540	240
SCE	Other	44	5,900
SCE	Residential	153	34,000
SDG&E	Commercial	86	1,800
SDG&E	Industrial	145	180
SDG&E	Residential	20	72,000

LBNL-Load and DR-PATH are used as an integrated package to simulate self-consistent energy futures cases with coincident and time-synchronized weather, loads, prices, renewable generation, and distributed technology scenarios. The cases help define the implications of qualitatively different future scenarios, and could be thought of as a sensitivity analysis. We also use a Monte Carlo approach to estimate many possible supply curves for each case.

The study's model includes end uses and dispatchable enabling technologies for this report listed below in Table 2:

Table 2: Summary of enabling technology options included in Phase 2 results.

Sector	End Use	Enabling Technology Summary
All	Battery-electric and plug-in hybrid vehicles	Level 1 and Level 2 charging interruption
	Behind-the-meter batteries	Automated DR (Auto-DR)
Residential	Air conditioning	Direct load control (DLC) and Smart communicating thermostats (Smart T-Stats)
	Pool pumps	DLC
Commercial	HVAC	Depending on site size, energy management system Auto-DR, DLC, and/or Smart T-Stats
	Lighting	A range of luminaire-level, zonal and standard control options
	Refrigerated warehouses	Auto-DR
Industrial	Processes and large facilities	Automated and manual load shedding and process interruption
	Agricultural pumping	Manual, DLC, and Auto-DR
	Data centers	Manual DR
	Wastewater treatment and pumping	Automated and manual DR

For Phase II, additional DR enabling technologies with faster communication and load data acquisition capabilities were added to the analysis. These added "Fast DR" technologies qualify or are expected to qualify for ancillary services and other market products which require faster response to a dispatch signal, with the fastest requirement of 4 seconds for regulation up or regulation down market participation.

As part of the process of determining which end-uses are currently or likely future Fast DR participants, LBNL surveyed a number of DR industry stakeholders (including aggregators, scheduling coordinators, ESCOs, and contractors).

The end-uses eligible for Fast DR included in this analysis are:

- Agricultural Pumping (including variable frequency pumps (VFPs)
- Commercial HVAC (with EMS and/or VFDs)
- Commercial Battery
- Commercial BEV and PHEV (fleet and public)
- Commercial Lighting (luminaire and zonal)
- Commercial Refrigerated Warehouses

- Industrial Battery
- Residential Battery
- Residential BEV and PHEV
- Wastewater Process and Pumping

We assume that for end-uses that can deliver Fast DR services, the same local control technology would be used as their "slow DR" equivalents, and that the main differences between Fast and Slow DR technologies are in the telemetry and dispatch configurations, with the exception of advanced technologies such as variable frequency drives and pumps. Therefore, the hardware and installation costs for Fast DR control technology are the same, and any additional costs are for the telemetry and communication system upgrades, which could be for metering, a resource interface, a gateway or another component.

3.2. RESOLVE Model

A key Phase 2 study feature is the use of the RESOLVE model to identify least-cost strategies for power system investment and operations. It optimizes in the context of constraints on meeting future renewable energy targets, operational requirements and capacity constraints on the grid. The planning period included in this study is 2016–2030.

RESOLVE was originally developed and is implemented by E3. During this project, the model was augmented to include a variety of DR services defined by LBNL and E3 – Shape, Shift, Shed and Shimmy. A key advantage of working with RESOLVE for this project was the ability to rapidly develop software modules for integrating the bottom-up DR future potential results executed by LBNL.

The work builds on RESOLVE cases for the CAISO area originally developed as part of the CAISO's studies of a regional market directed by Senate Bill 350 – the Clean Energy and Pollution Reduction Act of 2015.[3] Some assumptions from these cases, such as carbon price forecasts and gas price forecasts, were developed for SB 350 work, and remain in the model. E3 adapted the cases for this project by incorporating additional functionality to model flexible loads and through updating assumptions around future system conditions. The assumptions are explained in detail in Appendix H.

We describe key features of RESOLVE below that make it well suited for this study: explicitly modeling the value from supporting renewables deployment consistent with California statutory requirements and including two cases for renewable integration technology deployment.

[3] For more on SB-350, see https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

3.2.1. Renewable Curtailment and Overbuild

An important consideration when looking at how DR can help California meet its RPS targets, a binding constraint in RESOLVE, is that of renewable curtailment and "overbuild." When large amounts of renewable generation is built, their power generation can occasionally exceed the combination of electricity demand and power export capability, requiring the renewable production to be curtailed to maintain reliable grid operations. The effect of this is that available renewable energy is forsaken to maintain grid stability, and therefore additional renewables need to be constructed with different generation profiles in order to ensure compliance with a 50 percent RPS target. When this happens, the renewable portfolio is referred to as "overbuilt"—more renewable energy production capacity is present than would otherwise be needed in the absence of curtailment. In particular, building additional renewables with similar generation profiles (e.g., solar PV) leads to increasing marginal curtailment, as each megawatt-hour added has more of its generation added to an hour where curtailment already occurs, leading to further curtailment.

Renewable integration solutions (e.g., energy storage, more flexible gas generation or transmission to deliver more renewable generation) are then valued for their ability to reduce curtailment (in addition to more common value streams such as reducing fuel costs and deferring new capacity needs). Because each of these solutions requires potentially significant up-front capital investment, E3's RESOLVE model found that some curtailment is optimal in future time periods when the cost of adding solutions is higher than the cost of simply overbuilding the renewable portfolio. This is particularly true in 2025 and 2030, as forecast renewable penetration increases. However, marginal curtailment eventually reaches a high enough level that other solutions (e.g., storage) become cost-effective. These dynamics give rise to one of the most important value sources for resources like DR, which can alter the load profile to reduce curtailment of renewables.

3.2.2. Modeling Electric System Futures

Previous work by E3 identified that the curtailment level and the choice of load forecast are significant determinants of the value of new resources like DR that can contribute provide power system services. To capture the impacts of curtailment on DR value, we selected two bounding "curtailment futures": a High-Curtailment future and a Low-Curtailment future. To ensure consistency with current CPUC assumptions, these futures were based on two scenarios from the 2016–2017 CAISO Transmission Planning Process.[4] The combinations of these assumptions provide four scenarios that bound our estimates for DR value. Table 3 lists the

[4] For more information on CAISO's 2016–2017 TPP, see CPUC Rulemaking 13-12-010, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673.

assumptions underlying each.

Table 3: "Curtailment Futures" modeled in RESOLVE.

	High-Curtailment Future (LTTP Scenario: "High BTM PV")	Low-Curtailment Future (LTTP Scenario: "Out-of-State Wind")
RPS	50% by 2030 (Out-of-state resources permitted)	50% by 2030 (Out-of-state resources permitted)
Export Limit	2,000 MW	2,000 MW
Incremental Wind (Beyond 33% RPS)	None	3,000 MW by 2025
Behind-the-Meter (BTM) PV	26.9 GW of BTM PV in 2030	19.1 GW of BTM PV in 2030
Utility-Scale Solar PV	13.0 of utility-scale PV in 2030	12.4 GW of utility-scale PV in 2030

The CPUC's RPS Calculator Model[5] is used to create renewable portfolios for each of these curtailment futures, consistent with the LTPP specifications. Renewable overbuild is modeled endogenously within RESOLVE; for more detail see Appendix H.

Figure 11 shows the resulting renewable generation portfolios in 2030, when meeting the 50 percent RPS target assumption. The major difference between the two portfolios is the additional 8.4 GW of solar PV (both behind-the-meter and utility-scale) included in the High-Curtailment future. Solar PV systems have very similar, diurnal generating profiles due to daily timing of solar insolation across California. Therefore, the LTTP's High BTM Scenario, with its high PV penetration, acts as our High-Curtailment future.

A number of geographic and temporal simplifications are made in order to achieve a reasonable model runtime while maintaining focus on key cost considerations:

- Investment decisions and operational dispatch are made in multi-year time increments: 2016, 2020, 2025, 2030

[5] For more information, see http://www.cpuc.ca.gov/RPS_Calculator/.

- 37 representative days are modeled in RESOLVE in each year. These 37 days with appropriate weights to be equivalent to full year are chosen to best represent a typical full year's load, renewables, hydro, net load conditions, as well as the annual monthly distribution of days.
- Investment decisions are made for the Balancing Authority Area operated by the California Independent System Operator ("CAISO"). Since Given the CAISO is interconnected with other balancing areas, RESOLVE incorporates a geographically coarse representation of neighboring regions in the West (the Northwest, Southwest, and Los Angeles Department of Water and Power (LADWP)) in order to characterize and constrain flows into and out of the CAISO.

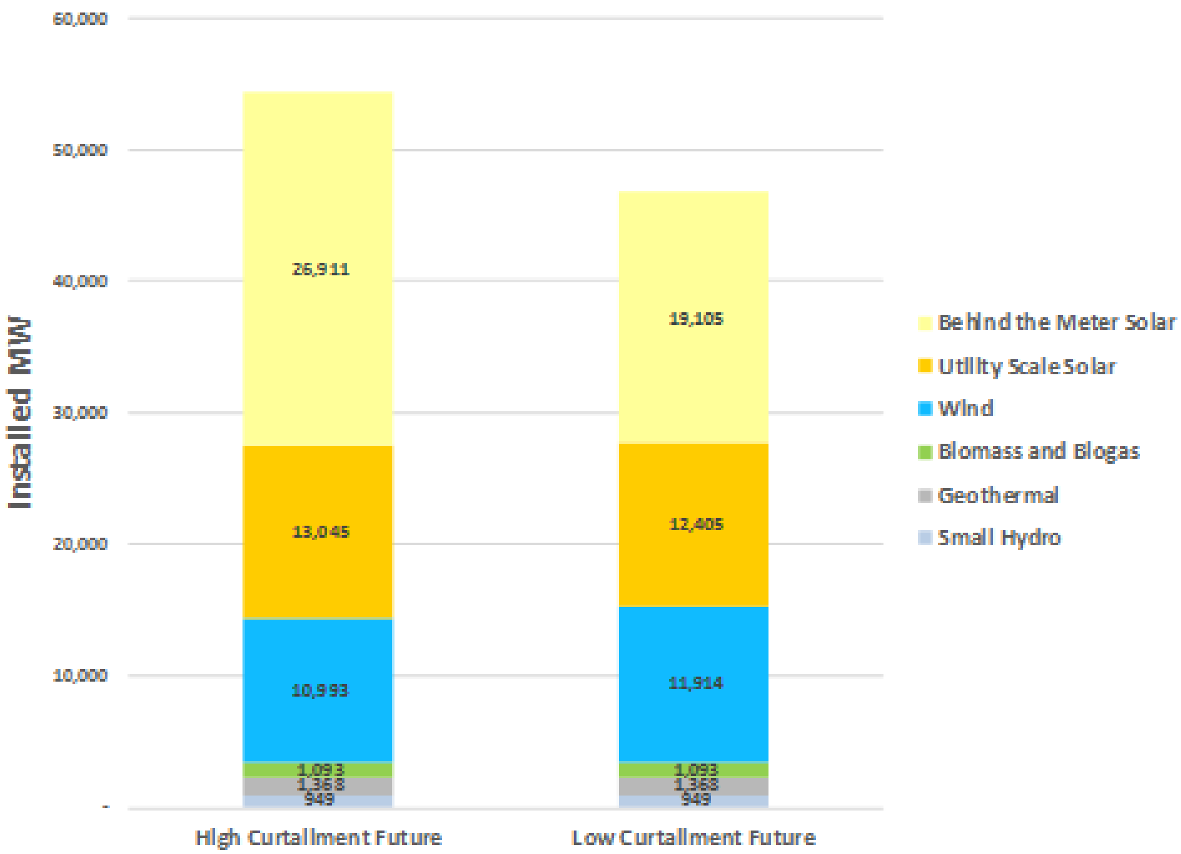


Figure 11: 2030 Renewable generation portfolios for High- and Low-Curtailment futures.

To quantify DR's value to the CAISO system, E3 began with a base case that contained no DR, and allowed RESOLVE to minimize system costs over the 2016–2030 investment period. Then DR was added to the system in increasing increments, and costs were minimized over the same period. Any decrease in system costs was attributed to the added DR resource. Figure 12 shows curtailment, by year, under the base case (i.e., with no DR).

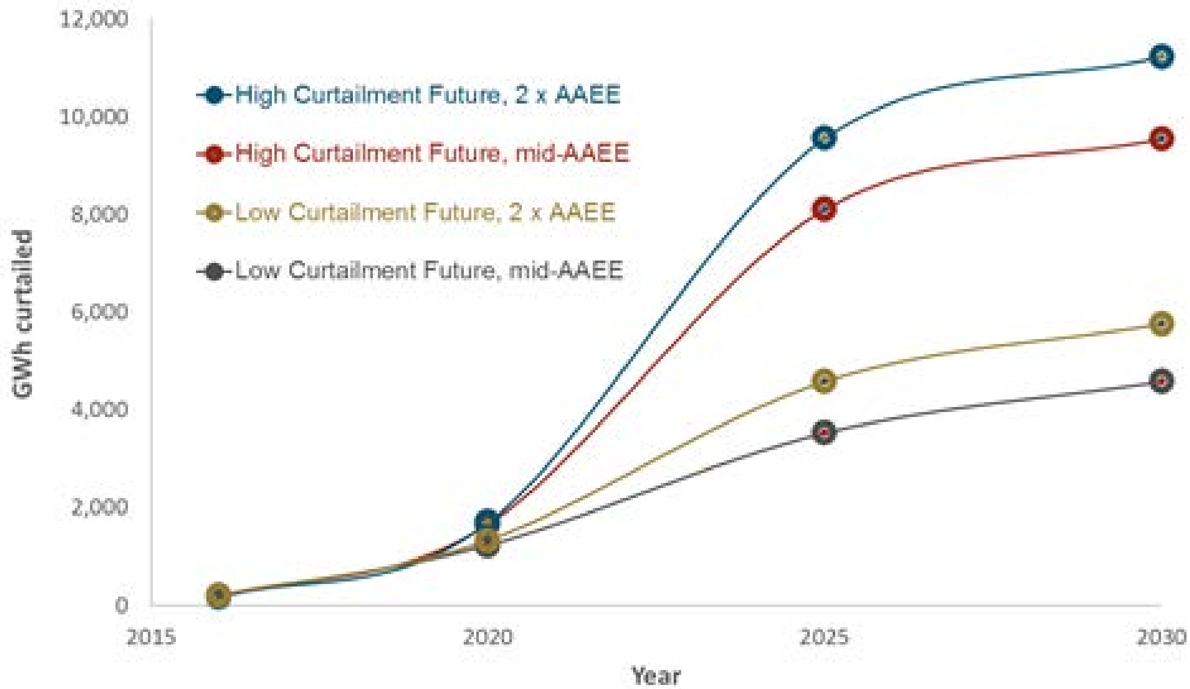


Figure 12: Base case curtailment, by year.

The High-Curtailment future has approximately 4,000–6,000 GWh (depending on load forecast assumption) more curtailment in 2025 and 2030 than the Low-Curtailment futures, due to their higher solar PV penetration. Doubling energy efficiency also increases curtailment by approximately 1,500–2,000 GWh. This is because lower loads in hours of high solar overgeneration increases curtailment, and this effect more than offsets any reduction in renewable energy procurement needed to meet the lower RPS requirement caused by lower load.

3.3. Demand Response Scenarios for Technology and Market Pathways

To forecast DR in California we defined three potential DR market and technology trajectory scenarios: (1) Business-as-Usual (BAU), (2) Medium, and (3) High. These three scenarios can be compared to the base scenario, which describes the DR market and technology characteristics at the time of this study, circa 2014–2015. The BAU scenario represents steady incremental improvement in technology performance and market adoption. The Medium and High scenarios explore what is possible with moderate and more aggressive technology and market transformations. Table 4 summarizes the assumptions that define the trajectory of cost, performance, and propensity to adopt DR for the three years modeled and reported: 2014, 2020 and 2025. Note that 2014 was chosen as the base year because it was the last full calendar year

for which smart meter hourly data were available prior to commencing this study.

Table 4: Summary of scenario defining model parameters.

Parameter	Parameter Description	Scenario	2014 Value	2020 Value	2025 Value
Cost	Full DR enabling technology cost relative to the base cost (lower is better)	BAU	1.00	1.00	1.00
		Medium	1.00	0.95	0.90
		High	1.00	0.85	0.70
Performance	DR service quantity (kW or end-use load fraction) available relative to base performance (higher is better)	BAU	1.00	1.05	1.10
		Medium	1.00	1.10	1.20
		High	1.00	1.20	1.40
Propensity	Likelihood to enroll and participate in DR relative to base propensity (higher is better)	BAU	1.00	1.05	1.10
		Medium	1.00	1.15	1.30
		High	1.00	1.25	1.50

3.3.1. Propensity Scores and DR Adoption Rate

The choices and preferences of electricity users and customers determine success or failure of DR programs—without initial and ongoing enrollment there will simply not be loads available to provide service to the grid.

In DR-PATH we model the likelihood of customers to adopt DR using statistical methods that combine the best available information on current-day DR program adoption rates and controlled studies to understand how demographic factors, incentives, and marketing combine to result in some fraction of customer adoption. **We refer to the expected fraction of customers as a "propensity score,"** in line with standard practice in economic analysis. Nexant Consulting, Inc. was the technical lead on developing the propensity score model, and the results of that model are used in combination with current-day enrollment. Details on the methods for propensity score estimation are available in Appendix F, including a description of factors that are estimated to influence propensity to adopt DR (which could be useful for broader work on DR as well).

__The study is designed for the next generation of DR applications__, which not only includes meeting peaking capacity, but also new and recent applications such as resources to meet longer and larger sustained ramps (ramping capacity), fast response to address renewable volatility and multiple up and down ramps throughout the day, and shifting of loads to avoid over-generation in the middle of the day. For most of these applications, there are no mature existing programs against which to benchmark.

The figures below are a synthesis of our estimates for the fraction of customers that will contribute to DR resource availability in 2025, using the Shed resource as an illustrative example. As the price of DR service goes up, additional incentive payments are available and our propensity score model yields higher expected participation rates. Note that the implied rate of participation for many end-uses is limited by adoption (e.g., EV and HVAC) but for others like batteries there is a possible pathway for every site. Overall, the participation rates are in the range of 5-10% (and much lower for commercial customers) for the region of the model where one would expect prices to settle (between 0-200 $/kW-year).

The following set of figures display the implied DR participation rates in 2025 by Sector. The line colors in each sub-plot correspond to end-use categories and the line types correspond to utility service areas. These results are a synthesis of a propensity score model and its implementation in DR-PATH across a range of technology and market pathways.

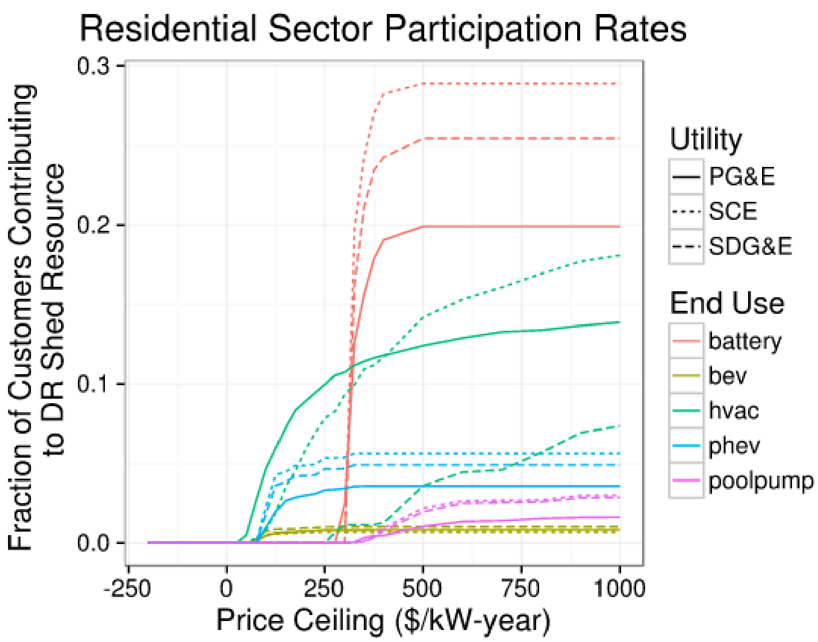


Figure 13: 2025 Residential Sector DR Shed Participation Rates per IOU and End Use at Varying Price Ceilings ($/kW-year).

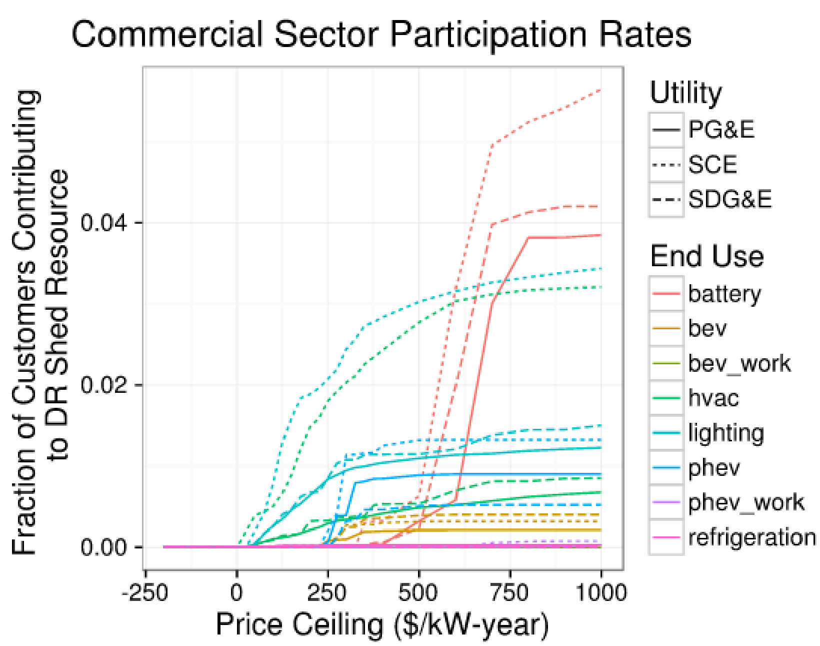


Figure 14: 2025 Commercial Sector DR Shed Participation Rates per IOU and End Use at Varying Price Ceilings ($/kW-year).

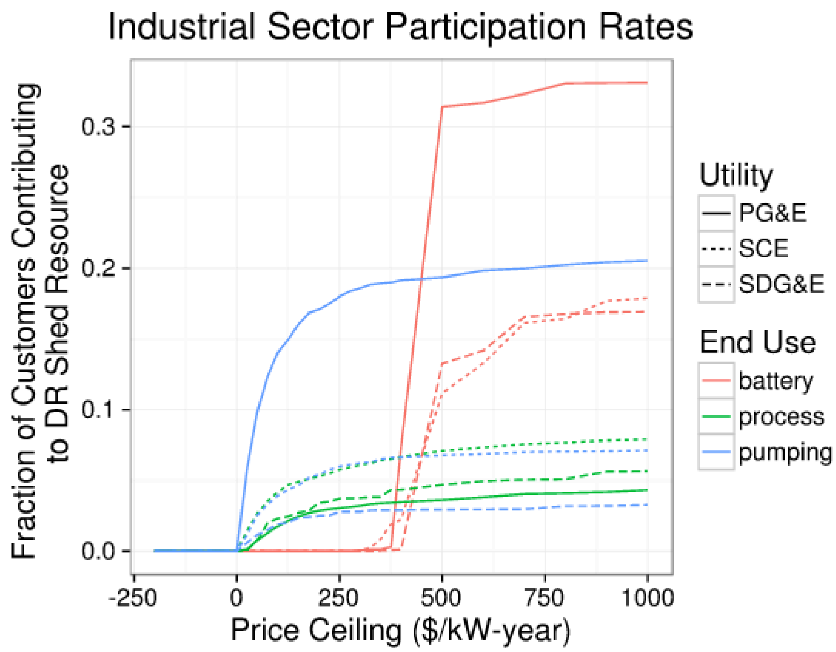


Figure 15: 2025 Industrial Sector DR Shed Participation Rates per IOU and End Use at Varying Price Ceilings ($/kW-year).

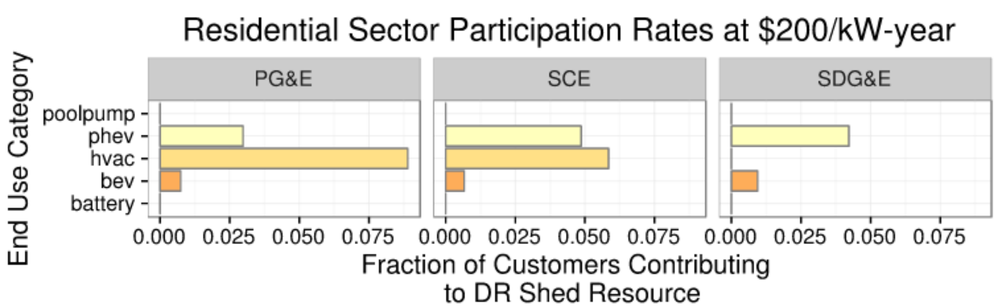


Figure 16: Residential Sector Participation Rates per IOU and End Use Category at $200/kW-year.

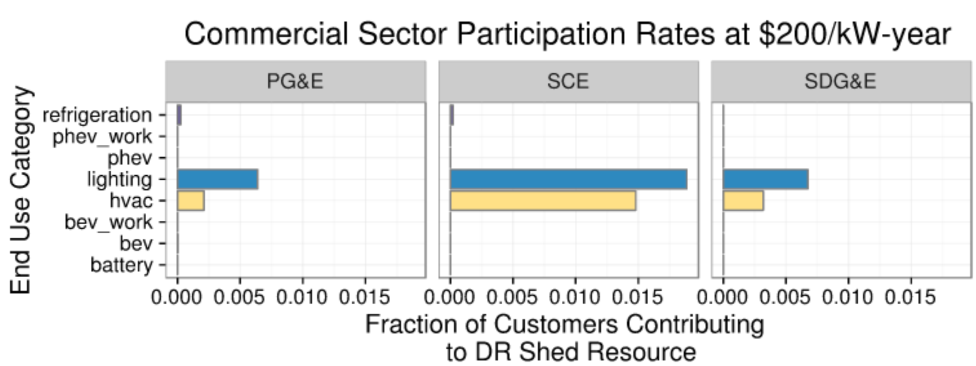


Figure 17: Commercial Sector Participation Rates per IOU and End Use Category at $200/kW-year.

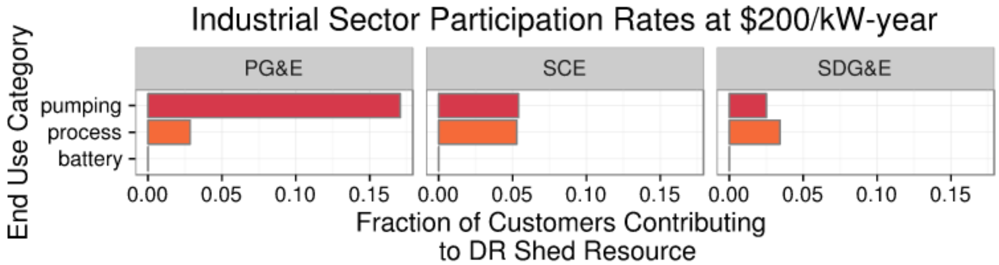


Figure 18: Industrial Sector Participation Rates per IOU and End Use Category at $200/kW-year.

3.4. Demand Response Service Types

Based on future grid needs, we defined four key "service types" (Table 5 ***below***) for which we estimated DR potential: Shape, Shed, Shift and Shimmy.

- **Shape** captures DR that reshapes the underlying load profile through relatively long-run price response or on behavioral campaigns—"load-modifying DR"—with advance notice of months to days. It provides value in our study as an alternative and low-cost path for achieving a level of energy "Shift" and peak load "Shed" (those service types described below). Our estimates of potential for Shape are either "Shape-as-Shift" or "Shape-as-Shed" equivalent values. The Shape technology pathways we modeled were time-of-use (TOU) and critical peak pricing (CPP) rates.
- **Shift** represents DR that encourages the movement of energy consumption from times of high demand to times of day when there is surplus of renewable generation. Shift could smooth net load ramps associated with daily patterns of solar energy generation. Examples of Shift technology pathways we include are behind-the-meter storage, rescheduling flexible batch processes[6] like EV charging fleets or pre-cooling with HVAC units.
- **Shed** describes loads that can occasionally be curtailed to provide peak capacity and support the system in emergency or contingency events—at the statewide level, in local areas of high load, and on the distribution system, with a range in dispatch advance notice times. Examples of Shed technology pathways we include are interruptible processes, advanced lighting controls, air-conditioner cycling, and behind-the-meter storage.
- **Shimmy** involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.

[6] A batch process is a processing mode: the execution of a series of programs on a set or "**batch**" of inputs, rather than a single input.

Examples of Shimmy technology pathways we include are advanced lighting, fast-response motor control, and EV charging.

These service types or resources stack span a range of possible California electrical grid needs mapped conceptually onto a timeline in Figure 19, ranging from years (addressed by Shape) to seconds (met by Shimmy and some Shed resources). These overlapping pathways for load flexibility across timescales are fundamental to cost-effectively supporting large-scale renewables on the grid. Next, we elaborated on these pathways for DR to provide value to the grid. These service types form the core of grid support products that are needed today and in the future in California. Previous studies for energy efficiency or distributed generation often treat the resources as “static” decentralized energy investments with deterministic outcomes, but DR investment outcomes are more probabilistic and depend on continued customer engagement for a durable resource. Furthermore, the value created by DR depends on the specific timescale of the response.

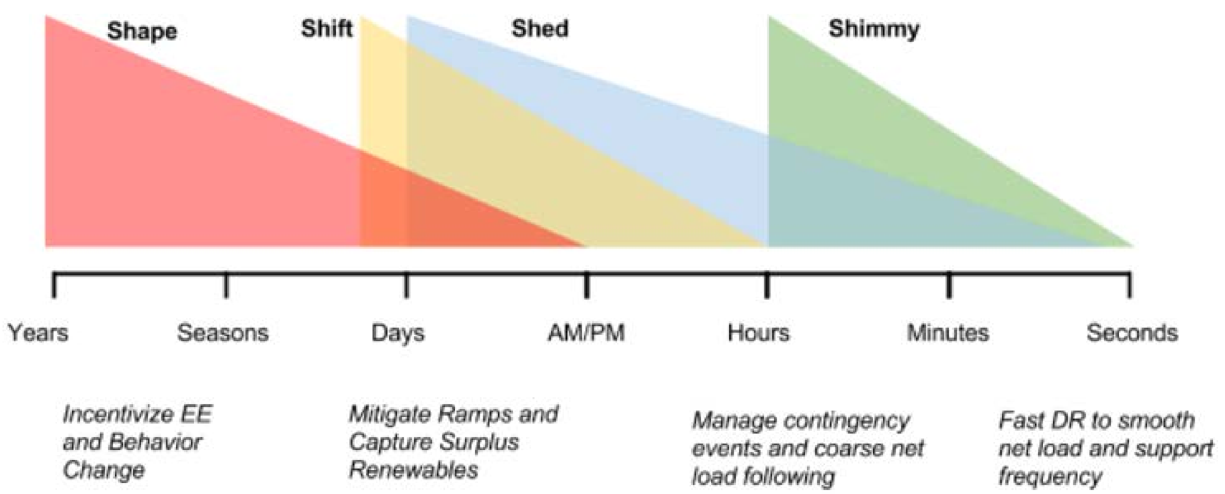


Figure 19: DR service types presented over timescale for grid service dispatch frequency and/or response.

Shaping the load with “slow changing” TOU rates and critical peak pricing is a long-term approach that results in structural changes to the stock of loads (e.g., energy efficiency investments).[7] These equipment changes, combined with behavior change, can provide some effective Shift and Shed resources without integrating them into an explicitly dispatched market. Shift resources are flexible loads that are dispatched to capture surplus renewable electricity,

[7] Lazar, J. 2016. *Electricity Regulation in the US: A Guide.* Second Edition. Montpelier, VT: The Regulatory Assistance Project. http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

and other strategies that effectively shift load from periods of high price and scarcity to load marginal cost; usually this means shifting from the morning and evening hours into the middle of the day, when solar electricity is abundant.

In this study, we modeled Shift as a dispatchable resource with enabling technology to respond to a signal. In principle this could be a centrally organized "market" for shifting energy or simply a dynamic price and/or instructions based on a price forecast. Shed resources include and go beyond conventional DR, which is often dispatched many hours or a day ahead to manage forecasted peaks at the system level. It also includes fast-shedding resources that can meet local capacity needs or distribution system needs, and respond in the event of contingency and emergency conditions. Finally, we define fast DR that can follow sub-hourly to seconds-level signals as Shimmy resources. The need for Shimmy is bounded based on the variability in the net load, but has high value for maintaining stability. In addition to the existing variability from a diverse set of loads, the growing fleet of solar and wind power generators introduces new kinds and scales of Shimmy-scale variation.

DR Participation in CAISO markets

Controllable DR resources, including behind the meter battery storage, can provide flexible services to existing wholesale markets that can potentially defer the need for additional conventional generation resources, with sufficient penetration. Controllable DR resources can support the integration of renewable energy sources, and support policy targets for renewable standards and a low carbon future. CAISO and the CPUC continue to develop rules that encourage broader participation of non-generator resources in the wholesale markets, including load following ancillary services.

A cooperative effort for developing market, policy, and technology systems for Shifting could result in novel models for compensating/incentivizing DR enablement and response. For example, flexible capacity credits could be awarded based on an expectation of future response as buy-down for appropriately specified control technology.

These DR Service Products all provide value to the grid, and are framed and valued differently in various balancing authority areas. In California, there are ranges of existing and emerging products for DR participation in CAISO markets, resources adequacy procurement, and at the retail or load-modifying level. We map these California DR markets to the Shape-Shift-Shed-Shimmy framework in Table 5 and Table 6 below. The choice to reframe market products into the more generic services framework was a conscious one, designed to ensure the results of the study are broadly applicable for future market structures that may not match current-day approaches. The mathematical formulations of the service types closely match CAISO and other requirements when possible (e.g., with conventional Shed). Another benefit we uncovered in the course of the study, is the usefulness of a shorthand lexicon for DR in having technical

exchanges of ideas about future policy and market operations. The short names trade detail in their specificity for broader and more accessible concepts in grid management, and facilitate discussions between building scientists, policy analysts and power systems experts without necessarily requiring specific and esoteric knowledge of California market processes.

Table 5: Demand response service types modeled in this study.

Service Type	**Description**	**Grid Service Products/Related Terms**	**Analysis Unit**	**Shape** (TOU/CPP) Included in service type analysis?
Shift	Demand timing shift (day-to-day)	Flexible ramping DR (avoid/reduce ramps), Energy market price smoothing	kWh-year	Yes
Shed	Peak load curtailment (occasional)	CAISO Proxy Demand Resources/Reliability DR Resources; Conventional DR, Local Capacity DR, Distribution System DR, RA Capacity, Operating Reserves	kW-year	Yes
Shimmy	Fast demand response	Regulation, load following, ancillary services	kW-year	No

Table 6: Demand Response service types mapped to California's conventional wholesale and retail market products. "#" indicates service products that are included in results from both DR-PATH and RESOLVE.

	DR Service Product	California Market	Description / Notes
Shed	Peak Capacity	System and Local RA Credit	Resource Adequacy planning capacity. Requires participation as Economic DR resource and 4-hour continuous response capability requirement.
	Economic DR	Economic DR / Proxy Demand Resource	Resources in the energy market. (Proxy Demand Resource). RDRR can also bid economically in energy markets.
	Contingency Reserve Capacity	AS- spinning	Dispatched within 10 minutes in response to system contingency events. Spinning reserves must also be frequency responsive. CAISO currently has no established method for allowing DR to provide this.
	Contingency Reserve Capacity	AS- non-spin reserves	Able to respond within ten minutes and run for at least 30 minutes. The sum of Spinning and Non-spinning Reserves should equal the largest single system contingency.
	Emergency DR	Emergency DR / Reliability DR Resource	Resource can only be called when the system is in dire condition with limited dispatch. Not always in CAISO markets, however resources in these programs must register as Reliability Demand Response Resources (RDRR) in CAISO to access the wholesale energy market.
	DR for Distribution System	Distribution	Manage targeted issues. California is not currently deploying this type of DR but is the subject of study in the DRP. The capacity value is related to investment deferral in the distribution system.
Shift	Economic DR	Combination of Energy Market Participation	One mechanism for dispatchable shift could be participation in the energy market, both as a "load down" resource like PDR, and as a "consuming" resource in other hours. Current proposals in the CAISO ESDR could lead to bidirectional energy market structures like this.
	Flexible Ramping Capacity	Flexible RA -- energy market participation w/ ramping response availability	DR that counts towards flexible RA. Requires participation in the market with economic bids and 3-hour continuous response capability.
Shimmy	Load Following	Flexible Ramping Product (similar)	"Load Following" is modeled in RESOLVE as a symmetric flexibility product on a 5-minute dispatch. The CAISO Flexible Ramping Product is capacity that is awarded in the real-time market, for either increasing or decreasing load but without symmetric dispatch. The resources ramp in five minutes.
	Regulating Reserve Capacity	AS- Regulation	Capacity that follows (in both the positive and negative direction) a 4-second ISO power signal. It requires 1-hour of continuous response. Capacity is limited by the resource's 5-minute ramp.
Shape	Load modifying DR - Event-based	CPP	Utility-dispatched DR. This can be used to reduce an LSE's capacity for System RA requirement by impacting its forecasted peak load. This can be dispatched through power, reliability, or price signaling.
	Load Modifying DR - Load shaping	TOU	This is either Permanent Load Shifting or TOU style DR. This impacts the whole load shape, not just the peak. This resource is active every day and not dispatchable.

3.4.1. Shape Resource Description

Shape resources represent the effect of "load-modifying" resources like TOU and CPP rates, and behavioral demand response programs that do not have direct automation tie-ins to load control equipment. They are not modeled specifically as a service type, but the load-modifying DR effects are values under the same framework as Shed and Shift for comparison to ISO-dispatched resources.[8] These long run (TOU) and day-ahead (CPP) behavioral responses are thus comparable to Shed and Shift, but accomplished through rates or behavioral event signals. For price responsive DR, demand was compared between a flat rate scenario and three different rate mix scenarios (see Appendix E) in order to calculate hourly Shape resource impacts. These building blocks for DR help clarify and reveal the pathways for providing value on California's electricity system with an increasingly renewable generation fleet.

This study includes an assessment of modified load shapes from the effects of TOU and CPP under three rate availability and enrollment mixes, but excludes the possible effects of additional enabling technology investment or responses from prices more closely connected with the real-time, locational marginal electricity prices. Behavioral DR based on signals other than retail price (i.e., normative messaging) were not explicitly modeled, but emerging evidence suggests these resources can provide load modifications similar to peak pricing events, albeit muted in load impact percentages. With more significant investments in automatically price-responsive technology and exposure to real-time dynamic prices, it could be possible to achieve a significant portion of the dispatchable "Shift" resource we identified using price signals as opposed to conventional dispatch.

3.4.2. Shift Service Type Description

Shift represents DR that encourages increased energy consumption during times of day when there is surplus of renewable generation and smooths net load ramps associated with daily solar energy generation patterns. Energy consumption is then reduced during evening hours when renewable generation ramps down and net load increases, thereby "shifting" energy consumption. Shift resources are estimated in terms of kilowatt-hours per day of shifted load—equivalent on first-order terms to excess battery capacity that is available for daily arbitrage.

The Shift service type is DR that moves load to desired times during the day. This involves one or more periods of Shed (load reduction) paired with one or more periods of take (increasing load) during a single calendar day. For this study, we constrain the shift to be energy-neutral, meaning that the total energy (kilowatt-hour) shed is equal to the energy taken. The dispatch

[8] See the Shape results for a description of this valuation methodology.

schedule of this resource is determined by grid needs (see Appendix H) and typically follows a pattern that aims to even out system load throughout the day. Therefore, Shift DR is often scheduled to take load during times of low net load (generally during the early afternoon solar peak) and shed load during peak net load hours (generally during the evening, when solar generation is low and demand is high). This resource supports many needs of the grid, including (1) reducing peak load, which improves reliability and reduces need for peaking generation units; (2) increasing midday energy consumption, which reduces solar energy curtailment; and (3) decreasing afternoon ramping needs, which is accomplished by the combination of (1) and (2).

The following end-use services provide the resources for Shift service types:

- **Thermal Shift:** refrigerated warehouses; air conditioning, heating and ventilation; water heating (boilers)
- **Batch Process Shift:** data center batch processes, waste water treatment and pumping, agricultural pumping
- **Electricity Storage:** batteries, electric vehicles, pumped hydroelectric storage (not modeled here)

Figure 20 shows Shift strategies' impacts. Shift resources generally provide value by moving loads into midday hours to eliminate overgeneration from solar PV.

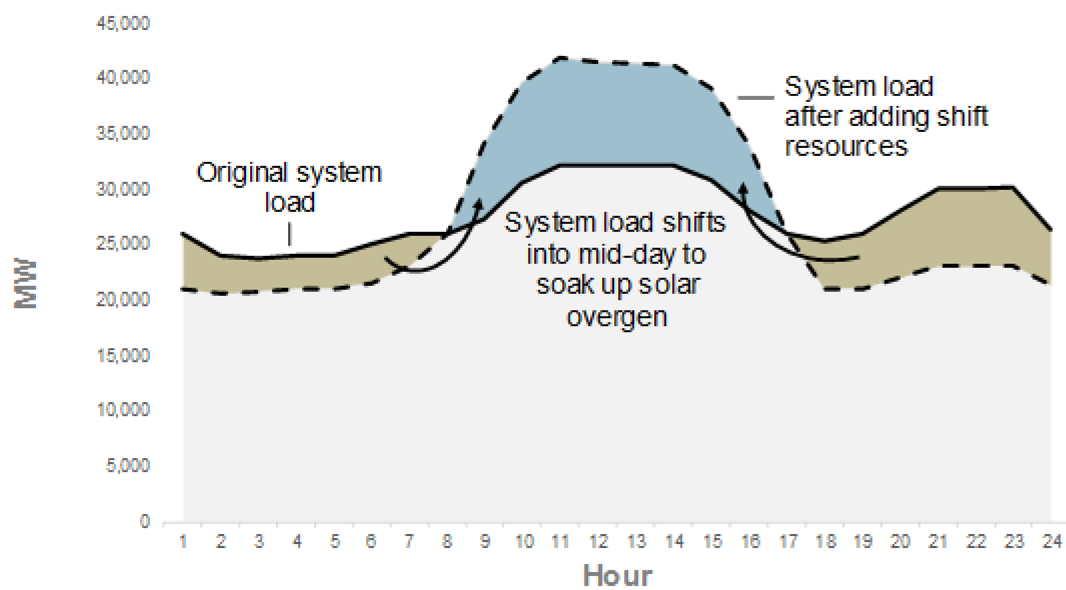


Figure 20: Illustrative Shift resource.

3.4.3. Shed Service Type Description

Shed describes loads that can occasionally be curtailed to avoid system upgrades and generation facilities related to peak capacity—at the statewide level, in local load pockets, and on the distribution system with a range in dispatch advance notice times. Shed is measured and estimated in terms of equivalence to a peak power generator that is available during the top 250 hours of the year, a heuristic we verified based on a parallel analysis of the estimated load-carrying capacity of demand response. Figure 21 presents the 2025 system load summary for gross, renewable, and net loads. The black dots indicate the top 250 hours used in our analysis of the Shed service type.

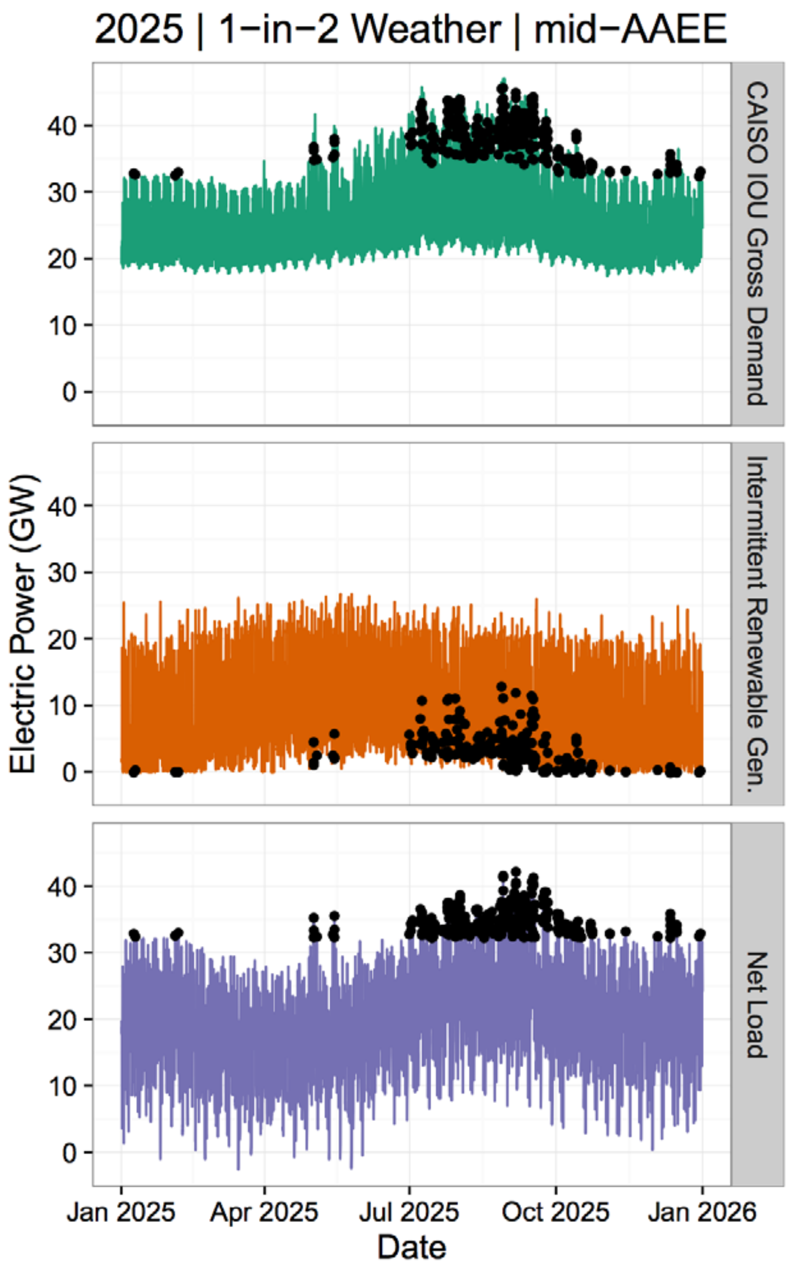


Figure 21: System load summary for 2025, in the 1-in-2 weather year. The black points indicate the top 250 hours of the year.

The Shed service type represents DR that is called to reduce customer load demand during peak net load hours. This is the service that was reported on in the current study's Phase, and represents traditional "hot summer day" DR. Shed service supports the grid by reducing the peak capacity required by the grid, and therefore improves reliability and reduces the need for expensive peaking generation units. Service interruption is the most common type of conventional DR, falling under the Shed service type category.

Figure 22 shows a representative illustration of Shed resources, also known as "conventional demand response." Dispatching Shed resources can potentially avoid the costs of building and running marginal gas peaker plants.

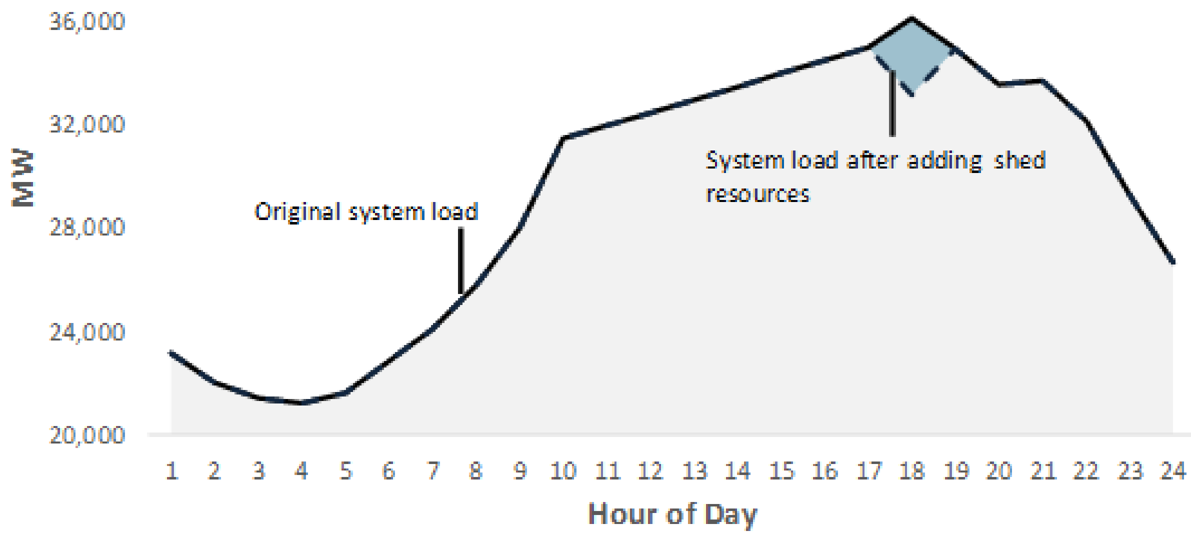


Figure 22: Illustrative Shed resource.

3.4.4. Shimmy Service Type Description

Shimmy involves using loads to dynamically adjust demand on the system to alleviate ramps and disturbances at timescales ranging from seconds up to an hour. Estimates for Shimmy are based on the annual weighted average availability of appropriately fast resources, with emphasis on hours when the price in the ancillary services regulating reserves markets is highest.

The Shimmy service type represents "Fast" DR and includes what is often referred to as ancillary services (AS), which support the continuous flow of energy through the grid to meet demand. In other words, this service corrects the real-time, continual gap between predicted (and therefore dispatched) demand and actual demand. This gap can be from either too much or too little predicted demand, and therefore Shimmy resources must be able to both take and shed load on a short timescale. We estimate DR potential for two types of Shimmy service: (1) load following, where the resource follows a five-minute dispatch signal, and (2) regulation, where the resource follows a four-second dispatch signal. Shimmy DR supports the grid by reducing the need for generation units to provide this service.

The Shimmy function of DR is shown in Figure 23. This reduces the need for other resources (e.g., storage, thermal generators) to provide these functions, leaving them more available to provide other value, such as freeing up batteries to charge during periods of overgeneration to reduce curtailment.

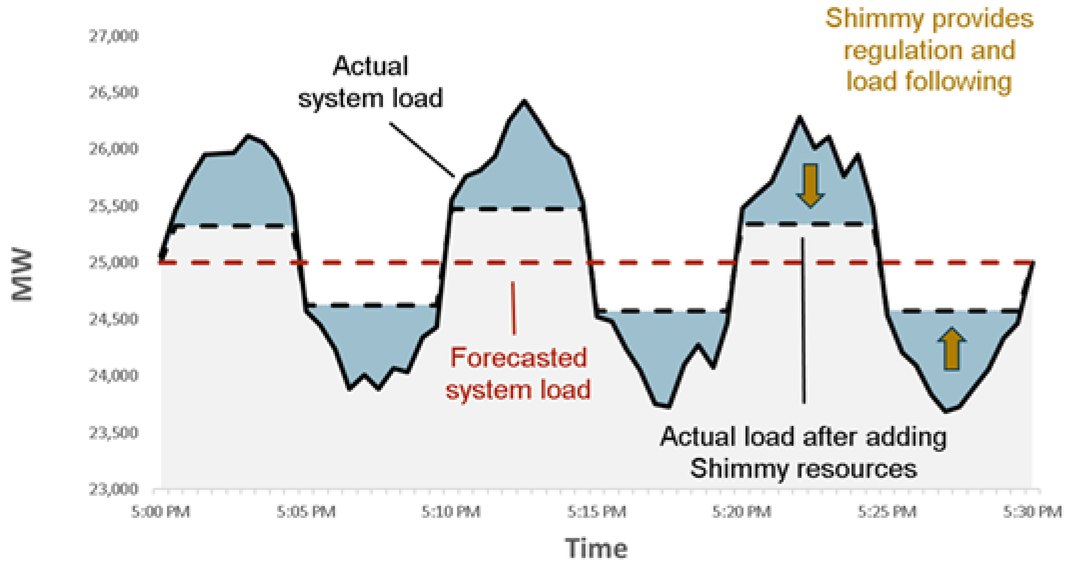


Figure 23: Illustrative Shimmy resource.

4. Economic Evaluation of DR Potential

4.1. DR Supply Curves

Results of this study are primarily represented in the form of DR supply curves (see Figure 24 for an example). These curves show the cumulative DR quantity available (x-axis) for a range of levelized DR cost values (y-axis). Different colors indicate different DR scenarios, with dotted lines indicating a 1-in-2 weather year, and solid lines indicating a 1-in-10 weather year. The DR quantity shown is the total across all utilities, customer clusters, end uses and available technologies. The units are either power (Shed, Shimmy) or energy (Shift) over the entire year, aggregated from hourly values as described in Appendix G. Levelized cost (y-axis) refers to annualized cost per unit of DR capacity, including technology costs, financing, marketing and administration. Shed and Shift services can be provided by the Shape resource (TOU and CPP), but this resource is not included in the supply curve calculations. Therefore, we represent the Shed or Shift DR provided by Shape as a bar at zero cost that effectively shifts the supply curve to the right.

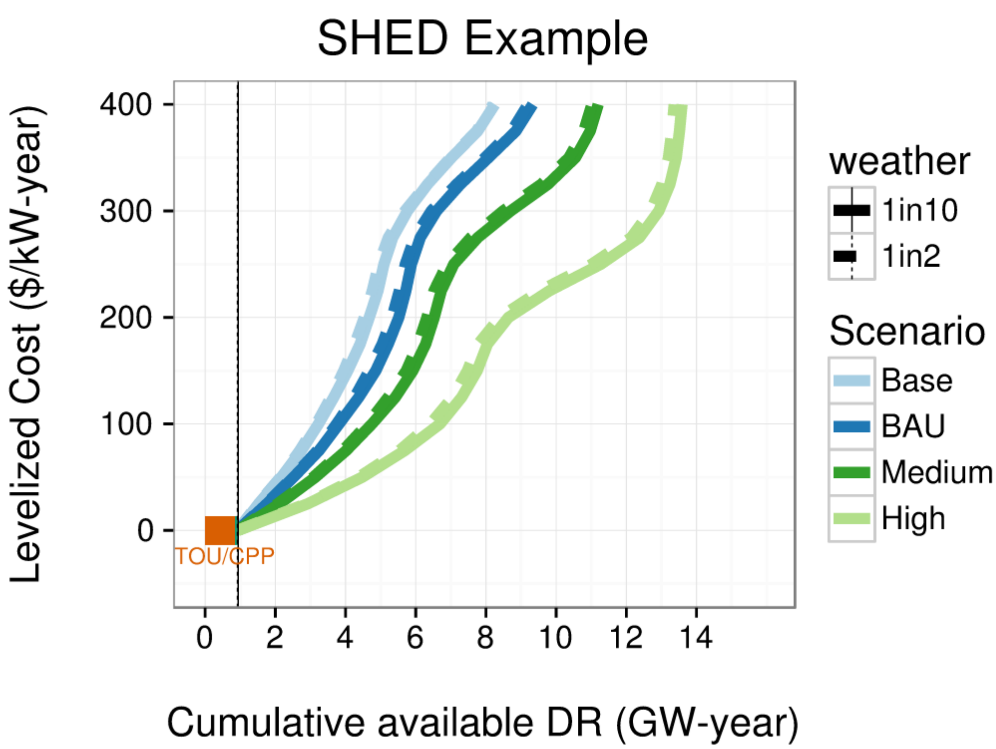


Figure 24: Example supply curve for Shed-type DR.

The cumulative available GW-yr of DR (x- axis) includes three potential DR market and technology trajectory scenarios: (1) Business-as-Usual (BAU), (2) Medium, and (3) High. Line

colors indicate the DR scenario; a solid line and dashed line is typical (1-in-2) and extreme (1-in-10) weather cases, respectively, under the Rate Mix #3.[9]

The DR supply curves we estimate are an expression of what types and quantity of DR will be available across a range of costs. The supply curves only include one "category" of DR (Shed, Shift, Shimmy), and have different scales and shapes, depending on the geographic scope of the analysis, market, and technology scenarios, and cost accounting frameworks. To evaluate whether and how much DR is economically viable, we compared the supply curves with estimates of the value of the specific service to the grid, using two different valuation methods: (1) price referent, and (2) levelized value, both described below.

4.2. Monte Carlo Simulation for Technology Uncertainty

We used Monte Carlo simulation to estimate how uncertainty in modeling assumptions affects the levelized cost of DR enablement, and we identified two key sources of uncertainty in estimating the cost of DR enabling technologies:

1. Uncertainty in expected cost/performance of emerging DR-enabling technologies, that is, the costs and performance of the DR technology available for sale in the U.S. market
2. Uncertainty in site-specific performance and enablement costs, that is, the costs to enable a site with the DR technology, and the actual performance at the premise

We simulate variability in modeling assumptions due to both sources of uncertainty by using stochastic sampling to populate the enabling cost, performance, and lifetime of each enabling technology for each cluster. We randomly sample values for each data field from distributions specified in the enabling technologies database described in Appendix G. Appendix G also provides a detailed description of the Monte Carlo simulation procedure.

We generate many realizations of stochastically populated inputs related to technology cost, performance and lifetime. In addition to these stochastic realizations, we generate one deterministic realization that contains inputs obtained directly from the literature without any stochastic variation.

Due to stochastic differences in modeling assumptions, the levelized cost of DR-enablement for a particular cluster differs in each of the realizations. These differences give us a range of supply curves. The results below include supply curves for all of the stochastic and deterministic

[9] Recall that the DR Potential estimates in this study are developed under the assumption that default TOU pricing will be in effect for all IOU customers. This assumption about TOU ultimately reduces the amount of load that is available for DR services, similar to advanced EE initiatives (SB 350). As we developed the supply curves of DR potential, we include load shapes that have been modified by Rate Mix #3, that is, our analysis applies the TOU load impacts to modify the base case load shapes which make an overall reduction to the load available for DR in each hour.

realizations, and box plots that show the range and distribution of results across realizations.

A simple example with two elements of the Monte Carlo simulation illustrated in Figure 25 below, using Residential "Smart" Thermostats as an example. There are two stages shown: Stage 1 establishes the average cost of technology for a given model run. The estimate is a random draw from a triangular distribution with a low, medium and high value. These Stage 1 estimates are the basis for the Stage 2, mid-point in which each site has a specific randomly selected value. The Monte Carlo estimates thus include variability related to broad market trends (Stage 1), and variability related to intrinsic site-to-site differences in the enabling technology cost (Stage 2). While the illustration only shows an enabling cost for technology and one performance metric, the implementation included a range of factors subject to variation: measure lifetime, operating costs, marketing cost, financing cost, administrative costs, and independent performance factors for each DR service type.

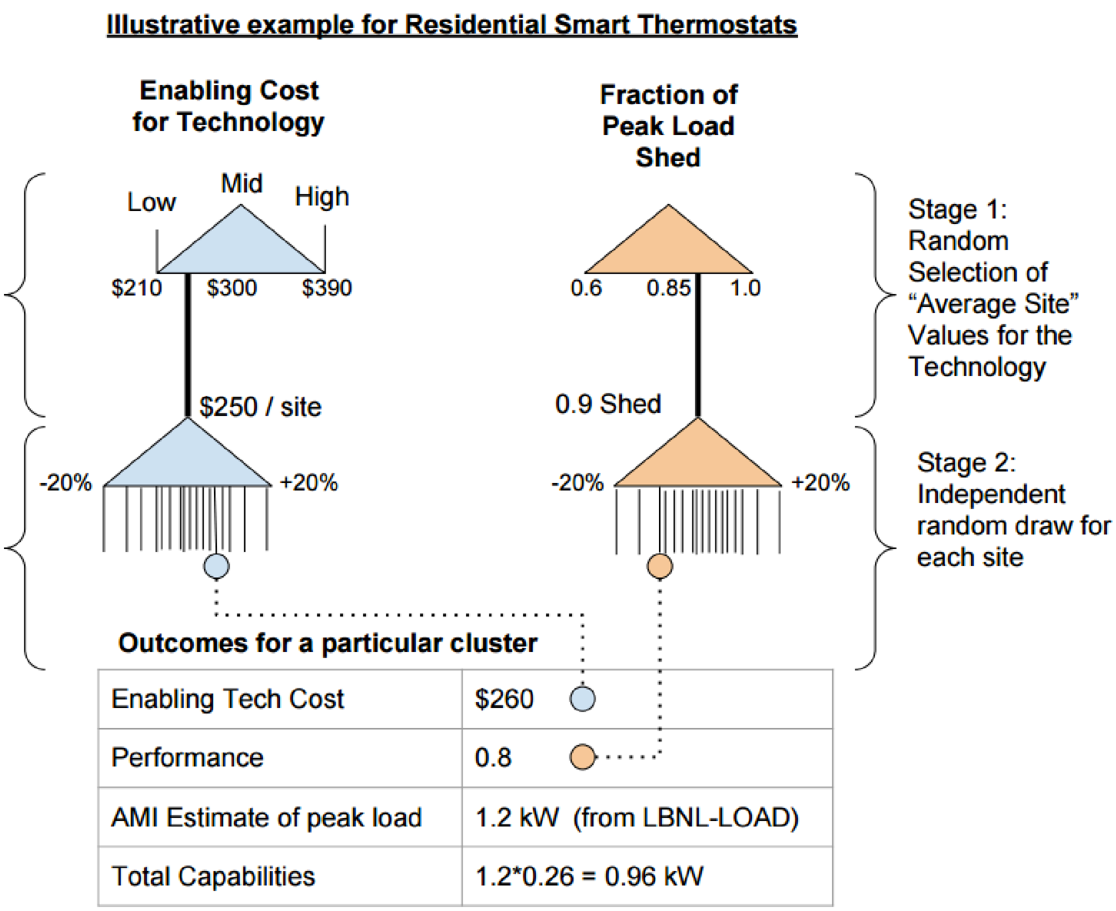


Figure 25: Illustration of Monte Carlo analysis approach for a simplified example.

4.3. Cost Perspective

When defining the cost of DR technology systems (i.e., the supply curves), we define the cost perspective as that of a DR aggregator who must pay for any incremental need for technology at a site, along with paying for incentives, program administration, marketing and any financing costs. The aggregator can receive revenue from wholesale market participation. The costs are presented in "levelized" terms—the expected average annual long-run cost, amortizing the initial cost of technology over its lifetime using a 7 percent weighted average cost of capital. In cases where technology is preexisting at a site (e.g., if a customer installs a smart communicating thermostat or there is preexisting control hardware from a previous DR program), we reduce the initial costs accordingly, based on the expected fraction of sites with that preexisting stock.

4.4. DR Sources of Revenue

Demand response services are able to receive revenue by participating in CAISO wholesale markets, as shown in Table 6. In this study, Shed services participate in the energy market and receive RA capacity payments, while Shimmy services participate in the AS market. Participation in other markets (including markets that do not yet exist) is possible but not quantified in this study. Such markets could include Reverse DR, where payments are given for taking additional energy from the grid, and Flexible Ramping capacity payments. Hourly prices for the energy and ancillary services markets quantified in this study are obtained from a PLEXOS simulation run by CAISO based on the 2014 LTPP scenario (CPUC 2013). We also consider high and low DR scenarios that capture price profiles where DR is more or less valuable to the grid. These scenarios are generated by increasing the price signal amplitude and multiplying the existing signal by a constant value (1.1 for the high-value scenario, and 0.9 for the low-value scenario). In all three scenarios, we maintain the upper and lower price caps specified in CAISO's modeling assumptions.

Table 6: CAISO markets considered for three DR service types. Checkmarks (✔represent market revenue calculated in this study, while asterisks (*) represent future potential sources of market revenue.

Service Type	Ancillary Services Market	Energy Market	Capacity and RA Payments	Flexible (Ramping) Capacity Payments	Reverse DR (future)
Shed		✔	✔		
Shift	*	*	*	*	*
Shimmy	✔				

Results for this study are aggregated to annual values, and therefore assumptions must be made for the dispatch frequency and timing of DR resources. Methods used to calculate annual revenue are directly tied to those used to aggregate hourly DR availability into annual values (Appendix I). Therefore, Shed DR energy market revenue is calculated as the total revenue earned in the top 250 net load hours of the year, where each hour of revenue is the amount of DR available times the market price. We do not include any market payments for Shift resources, but note that if significant market integration challenges are overcome there could be opportunities in a range of markets. Shimmy services are assumed to be needed during all hours of the year, and the expected annual revenue is the sum of hourly availability times hourly market price, with an assumption that shimmy resources are dispatched for an average of four hours per day.

4.5. Cost Frameworks

Our results include four cost frameworks that include various adjustments to the cost of DR resources at the system level. These "cost frames" enable understanding of how the portfolio of value that is provided by DR technologies can change the estimates of how much is cost-effective. In the cost frame listing below we include the shorthand description for each that is used in

1. **Gross total cost: ("Total")** The full cost of DR technology, soft installation costs, administration, marketing, incentives, and maintenance is included in the cost of services.
2. **Net cost with ISO market revenue stream**s ("Net Revenue")**:** Under this adjustment, the DR supply curves were adjusted to be lower, based on expected market revenue streams, such as energy market revenues, that effectively decrease the levelized annual

cost of DR technologies that can provide the DR service type.

3. **Net cost with revenue streams and site co-benefits ("Net Revenue + Site Co-benefits"):** Same as 2 above with the addition of co-benefits based on site-level value included to "buydown" the upfront capital costs of DR technologies. For certain end uses, the same technologies or device upgrades—such as smart thermostats, building energy management systems (EMS) or lighting controls—that enable DR also produce other cost benefits because they also allow a building to operate more efficiently (Goldman et al. 2010). Co-benefits were modeled as a percentage of enabling technology costs by which the upfront cost attributed to DR would be reduced. We applied co-benefits only to the following end uses: lighting (luminaire-level, zone level) controls, refrigerated warehouses, residential air conditioning (smart thermostat), commercial HVAC (EMS), EV chargers and batteries. In the co-benefits analysis, we made an assumption that the value DR investments provide to sites can be monetized by the aggregator, or that DR is adopted as part of a portfolio of measures where the portfolio approach leads to spillover cost reductions for DR.
4. **Net cost with revenue streams, co-benefits, and distribution system services ("Net Revenue + Site + Distribution Sys."):** Same as 3 above with the addition of revenue from serving the needs of the distribution system in ways that reduce the cost of operating or maintaining the system. We included an example set of possible distribution system benefits in the model, based on typical ranges of values and not based on an explicit model of distribution system needs. Our approach assigned a randomly selected distribution system value based on an expected range of values, where most sites have very low value (no constraint on the distribution system that needs serving) while a few have moderate to high value (where there are constraints on the distribution system that can be mediated with DR service).

4.6. Co-Benefits of DR Technologies

For certain end uses, the same technologies or device upgrades that enable DR (e.g., smart thermostats, building EMS, or lighting controls) produce other cost benefits by allowing a building to operate more efficiently (Goldman et al. 2010). These economic benefits are referred to in this study as "co-benefits," and were modeled as a percentage of enabling technology costs by which the upfront cost attributed to DR would be reduced. In practice, co-benefits could be realized through customer bill savings that come from DR-device-induced efficiency or energy efficiency (EE) incentives paid by a third party that help buydown the upfront cost of DR. Co-benefits were included in our study for the following end uses: lighting (luminaire-level, zone level) controls, refrigerated warehouses, residential air conditioning (smart thermostat), commercial HVAC (EMS), EV chargers, and batteries.

A previous study (Starr et al. 2014) showed co-benefits of implementing EE and DR measures

together in a refrigeration system in the range of 25 to 40 percent, primarily from jointly completing the design, installation, commissioning, and incentives at the same time. However, in our study, to be more conservative, we assumed 33 percent co-benefits (the average of 25 percent and 40 percent; see Table 7) for the end uses that are considered (residential air conditioning smart thermostats, commercial HVAC with EMS, and refrigerated warehouses). Based on storage value streams collected from the Rocky Mountain Institute, we assumed a co-benefit of 50 percent for batteries, which in addition to savings from TOU price arbitrage and improved reliability locally (i.e., keeping critical loads working with backup power) can also provide co-benefits when linked with rooftop solar PV. We assumed co-benefits of 75 percent for lighting (luminaire and zonal), which has controls typically installed to receive energy savings benefits. Lastly, we assumed that the co-benefits of PHEV and battery electric vehicle (BEV) charging were 75 percent.

For added fast DR technologies such as variable frequency drive pumps or motors for agriculture, wastewater pumping, and wastewater process, we assumed a co-benefit of 75 percent from energy savings.

Table 7: Summary of DR technology co-benefits. Co-benefits reduce the cost of the technology by a defined fraction of the initial cost.

End-Use and DR-Enabling Tech	Initial DR Technology Cost Reduction from Co-Benefit	Potential sources of Co-benefits
Commercial and Residential HVAC (EMS and Smart Thermostat)	30%	Energy efficiency and kW reduction
Refrigerated Warehouses	30%	Energy efficiency and kW reduction
Batteries	50%	Consumption optimization, kW reduction, backup energy supply
Agricultural Pumps	75%	Energy efficiency, kW reduction and controllability
Wastewater Process and Pumping technologies	75%	Energy efficiency, kW reduction and controllability
Commercial and Residential BEV and PHEV Level 1 and 2 charging (Fleet and Public)	75%	Fast Charging and controllability
Lighting (Luminaire-level and Zonal)	75%	Energy efficiency and kW reduction

4.7. DR's Value to the Distribution system

For constrained feeders, value may be captured by DR technology **if the DR can be reliably dispatched and controlled to support distribution system operations.** In the version of the model used for this report we *randomly assigned* these "distribution system co-benefits" throughout IOU service territories as an illustrative case in the model results. Pilot studies have shown that distribution system DR value is highly concentrated and depends on feeder-level diversity. Our assumptions were a synthesis of possible cases that mirror early understanding of

potential, and are described in Table 8 below wherein, distribution system benefits were randomly assigned within the DR Futures model throughout the IOU service territories to model, at first order, the potential cost savings from avoiding distribution system infrastructure upgrades required from load growth.

Table 8: Distribution system DR benefits assumption summary.

Distribution system DR illustrative example assumptions	
Performance Estimate	Equivalent to "conventional DR" shed in magnitude (limited by installed equipment capacity as well). Does not change propensity to adopt.
Mean Value	$25/kW-year systemwide
Site-Specific Value Assignment ***(Modeled as Truncated Log-Normal)***	• 50% of sites < $1.50 /kW-y • 75th percentile is $20/kW-y • Only top 5% of sites $160–$300

4.8. Economic Synthesis of Results

The supply curves are generated under the various cost frameworks discussed above and provide a visual representation and tool for interpreting the available DR resource where it intersects a given demand curve in our forecasted scenarios and weather years.

The third tool utilized for this study was the Renewable Energy Solutions (RESOLVE) model, developed by Energy and Environmental Economics (E3). RESOLVE is a power system operations and dispatch model that minimizes operational and investment costs over a defined time period by selecting an optimal portfolio of generation, storage, and demand-side resources.

The results provided by the DR-Path model are fundamentally represented in terms of supply curves that express the available quantity of particular DR resources across a range of possible costs for that DR resource. These results, like all of the results we show, are "levelized" costs, meaning they are the total cost of providing the DR service (e.g., upfront investment in equipment and enabling technology with ongoing annual operating expenses) amortized over the useful life of the DR technology. The decision of "how much DR" is useful requires a comparison of these costs to the value of service, providing estimates of economically cost-

effective DR. We used two different methods to make these comparisons, both shown in Figure 26. We refer to these valuation methods as (1) the price referent approach, and (2) the system levelized value approach.

The Price Referent Approach: One method for comparing the available supply to a value is to define a "price referent," which is the cost of procuring an alternative resource that could meet the same needs as the DR service (e.g., a natural gas combustion turbine that could carry peak load instead of peak Shed DR). If you assume that these resources will need to be procured one way or another, the price referent effectively sets a DR cost ceiling, below which any available DR is economically more cost-effective than an alternative resource. We only implemented the price referent approach for analyzing Peak Shed DR, which is comparable to the conventional economic assessment of Peak Capacity DR. When programmatic peak capacity programs are assessed for cost-effectiveness, they are done at a portfolio level of resources (e.g., residential DLC program over an entire IOU territory) and compared to an administratively defined (4 pm to 9 pm) number of hours in the summer. In our approach, the supply curves for each site level end-use enabling technology described the availability and controllability for each resource in the top 250 net load hours, defined the costs, assigned benefit streams, and compared that supply curve to the price referent.

The System Levelized Value Approach: Another method for comparing supply with the value to the grid is to use explicitly defined "levelized value curves" for service (which are analogous to demand curves). In this study we used the RESOLVE model to estimate the effective value of DR by introducing a range of zero-cost quantities of DR into the model. RESOLVE estimates of the total cost of operating and investing in the grid, and we used the difference in the total cost before and after DR is available to estimate the value provided to the system for a given quantity of DR. RESOLVE expresses a range of pathways to value: avoiding investment in conventional generation, reducing costs of renewable portfolio requirements, and operational savings. We used the average total "levelized value" to identify where the cost of supplying DR was lower than the value created. The system levelized value approach utilizes the intersection of a supply curve and levelized value demand curve as an estimate of the equilibrium, where the cost of additional DR supply equals the value created. Demand response with a unit cost below this equilibrium price is considered economically cost-effective. We used the levelized value method for assessing potential for each of the supply-DR options: Shed, Shift and Shimmy.

In both cases—the price referent approach and levelized value approach—the resulting DR potential takes on a range of cost-effective quantities. These depend on the differences between possible supply curves (e.g., from one DR scenario to another) and on the particular price referent or levelized value curve that was the basis for comparison. Note that in Figure 26, we show how when there are cases with relatively "flat" supply curves there can be a wide range of quantity estimates if the price referent is used, or if the levelized value curve is flat in the region of intersection. Our economic analysis provides a range of benchmark cases for which DR type

is and is not cost-effective, given different system conditions and for different system services. The price referent informs cost-effective benchmarks for load curtailment at the coincidence of distribution, transmission, and generation avoided costs. The RESOLVE model and levelized value curves identify DR that is cost-effective for overgeneration and ramping, given system conditions for a high RE future.

In this study, we explored the sensitivity of the estimates for DR potential in a variety of ways using DR scenarios (business-as-usual, medium, and high) that provide qualitative categories for market trends, with RESOLVE scenarios that show the differences in the value of DR based on whether there is relatively low- or high-curtailment of renewable electricity expected, and with a "Monte Carlo" approach to estimating many possible supply curves for each scenario.

The illustrative examples in Figure 26 are meant to clarify how the elements of DR supply and demand curves are constructed. The supply curves are colored based on DR scenario, and are adjusted if there is load-modifying DR (e.g., TOU price) that provides an equivalent service. The demand curves take the form of either price referent or system levelized value curves.

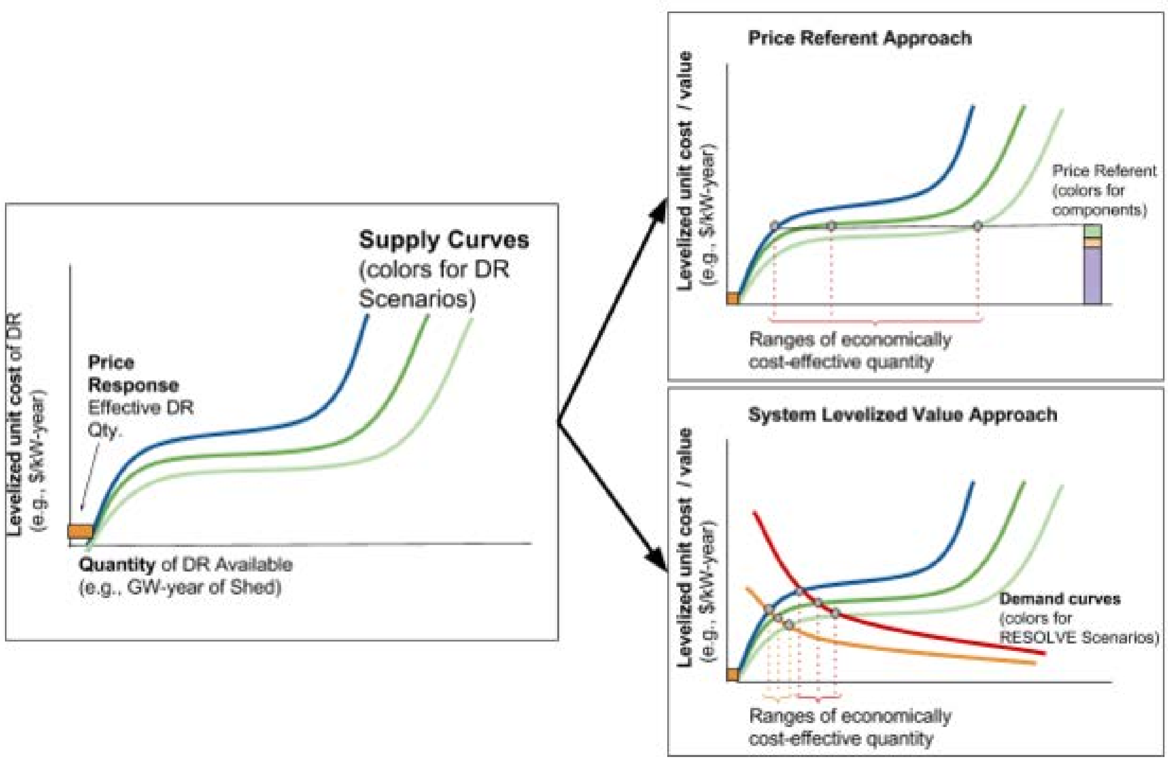


Figure 26: Illustrative diagram showing two approaches for DR economic valuation used in this study: Price Referent and System Levelized Value.

5. Results and Discussion

5.1. Demand Response Futures

This study's findings suggest that there are many opportunities for flexible loads to provide value to the operation of a renewably powered electricity system and improve the performance of investments in generation capacity and infrastructure. The needs of the system and capabilities of flexible loads span a range of timescales and geographic focus areas—from fast DR providing regulation to hours- or day-ahead response. In this section, we go into greater detail to discuss **Shape**, **Shift**, **Shed** and **Shimmy** DR services.

The Phase 2 study analysis includes results from E3's RESOLVE model, which estimated the value of DR to the CAISO system while addressing California's complex energy future with increasing RPS requirements and energy efficiency targets. The RESOLVE model introduced DR into a co-optimization model as a resource with no costs, and determined the value by examining the operational and fixed cost savings that result from each incremental megawatt of the DR service types that reduce the need to curtail renewable resources.

From the RESOLVE model results, we constructed demand curves based on the value of the DR, but these do not incorporate any costs associated DR procurement. Rather, the LBNL DR Futures model estimated those costs in developing the supply curves. Each model provided a value for DR; the RESOLVE model estimated the value to the CAISO system, while the DR Futures model estimated the costs of providing the DR services.

In the following sections, we present E3's analysis results from the RESOLVE model. For each service type category (Shed, Shift and Shimmy), results were produced by integrating the RESOLVE demand curves with the DR Futures' supply curves. It should be noted that E3 modeled each of the above advanced DR technologies at zero implementation cost. Thus, the economic results discussed in this report reflect merely the economic *benefits*.

5.2. *Shape* – Price Response

The Shape resource simulates DR potential through load modification in response to price signals such as TOU or CPP, or via behavioral signals, such as normative comparisons or public appeal. Exposing end users to time-varied prices can induce load shifts and sheds that meet the same needs as directly dispatchable technology—a long run reshaping of the daily load. This and other price-based "load-modifying" DR can provide significant value. In this study, we introduced three TOU/CPP rate scenarios in addition to a flat rate scenario, each of which provided the inputs for the Shape DR resource. Nexant developed estimates of residential load

impacts,[10] which LBNL then used to model the systemwide load impacts from three mixes of retail rates, as summarized in Table 9. For a detailed description of the rates and assumptions utilized in each of the rate mixes, see Appendix E.

The Shape resource was analyzed with three different rate mixes (described in Table 9 below) within the context of two service types. We estimated the shape resource potential in terms of how it could provide Shed or Shift services through load impacts. The amount of Shed DR provided was quantified by determining the resource's ability to reduce load during the top 250 hours; this was the method used for all Shed resources. This allowed us to attribute market revenues and distribution system benefits consistently, prescribing value to Shape resources over the top load hours of the year. We also examined the impact of the Shape resource as a Shift service type, where we quantified the amount of energy shifted daily during desired dispatch hours as a result of customer response to price signals or behavior based programs[11].

It is important to note the way TOU and CPP are organized and presented in the supply curve results framework. Because TOU and CPP are load-modifying demand response (LMDR), we excluded them from "participating" in the supply side resources for RA. Rather, TOU/CPP scenarios provided LMDR as a base load shift and supply-side DR resources were procured and utilized in addition to that base load shift. Therefore, TOU and CPP impacts effectively shifted the supply curves to the right, as portrayed by horizontal bars along the x-axis that start at 0 GW and extend to the estimated Shape DR impact.

The Shape resource includes behavioral responses to price signals or behavioral signals, (e.g., Flex Your Power and behavioral demand response programs). In our evaluation, we included TOU and CPP rate price signals and considered behavioral programs to produce similar, but muted, load modifications as CPP signals. Below we provide an overview of the assumptions and considerations for the shape resource analysis.

5.2.1. Residential TOU Rate Mixes for Shape Service

Figure 27 illustrates the hourly TOU pricing structure for PG&E's option 2[12] and SCE's Option

[10] See Appendix E for more information on the methodology for developing price response load impacts, rates, and elasticities.

[11] Note that Shape as Shift is modeled as a load modifying resource where Shape is modeled with the same parameters as the Shift service types, but as price response and not dispatchable. In contrast, the Shift service type resources are modeled as dispatchable supply side DR services.

[12] PG&E Advice Letter 4764-E Residential TOU pilot rates https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4764-E.pdf.

3,[13] from the Residential TOU pilot Advice Letters filed in December 2015. PG&E's Option 2 features a peak period from 6–9 pm during all seasons, with an additional off-peak from 4–6 pm and 9–10 pm in the summer. SCE's Option 3 features similar, but longer, peak (4–9 pm) and partial peak (11 am–4 pm and 9–11 pm in the summer) periods, with an additional "super off-peak" period from 11 am–4 pm in the spring. For the commercial sector, we include default TOU and CPP rates under all three rate mix options.[14] These rate structures, along with a standard flat rate and a CPP option, were combined to generate the three rate mixes used in this study (Table 9).

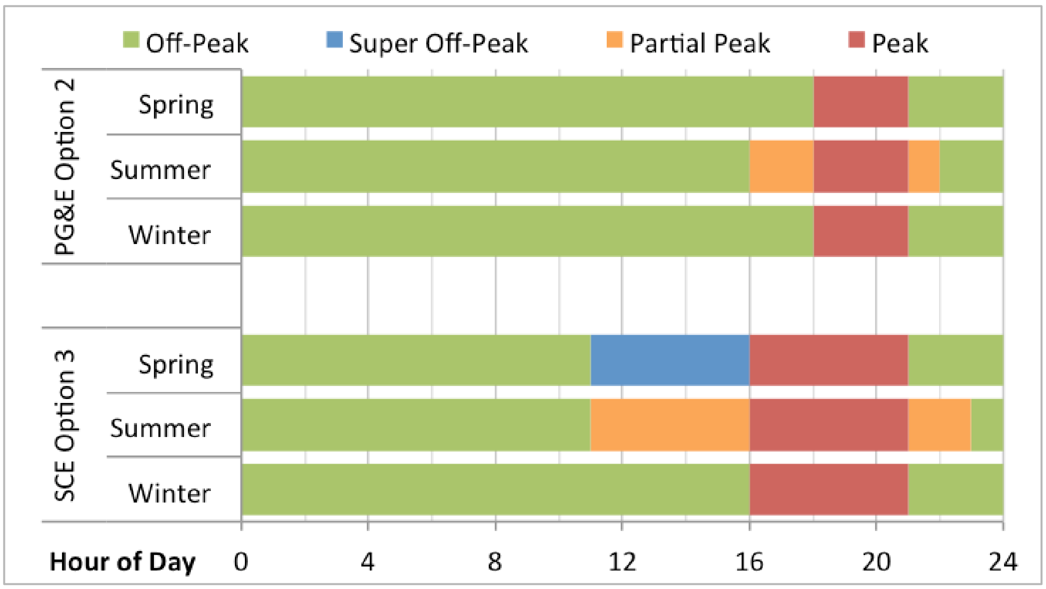


Figure 27: Time-of-use hourly structure for PG&E Option 2 and SCE rate Option 3 peak, off-peak, super off-peak, and partial peak periods.

[13] SCE Advice Letter 3335-E and 3335-E-A Residential TOU pilot rates https://www.sce.com/NR/sc3/tm2/pdf/3335-E-A.pdf.

[14] See Appendix E-6 "Price Responsiveness Model" for more information on the commercial sector TOU and CPP rates and assumptions used in this analysis.

Table 9: Shape resource retail rate mixes.

Rate Mix	Residential			Non-Residential
	Default	Opt-in	Default Opt-out	
Rate Mix 1	PG&E Opt 2	SCE Opt 3	PG&E Flat	TOU and CPP impacts derived from CA Statewide TOU Load Impact report, Christenson 2015.
Rate Mix 2	PG&E Opt 2	CPP	PG&E Flat	
Rate Mix 3	PG&E Opt 2	—	PG&E Flat	

Rate Mix #1 is structured as follows for all residential customers in the IOU service territories:

- PG&E Option #2 as the default rate with 75 percent enrollment
- SCE Option #3 as an opt-in rate with 15 percent enrollment
- Standard rate for customers that opt out of the default tariff with 10 percent enrollment

Rate Mix #2 is structured as follows:

- PG&E Option #2 as the default rate with enrollment at 90 percent of customers.
- Critical Peak Pricing (CPP) as an opt-in rate with a 15 percent customer enrollment rate
    - Customers that opt in to the CPP rate are also enrolled in the PG&E Option #2 TOU rate (dual participation)
- PG&E Standard flat rate for 10 percent of customers that opt out of the default tariff

Rate Mix #3 is structured as follows:

- PG&E Option #2 as the default rate with 90 percent enrollment
- Standard rate for customers that opt out of the default tariff with 10 percent enrollment

Figure 28 presents the amount of Shed service that can be provided by Shape resources ("Shape-as-Shed"). The x-axis indicates the total Shed DR GW provided by the various TOU/CPP rate mixes. The Shape-as-Shed DR resource is calculated by taking the price response load impacts from the top 250 hours of the year. We estimated that under Rate Mix #1, approximately 0.9

GW of load reduction is achievable from the residential and non-residential customer sectors during the top 250 net load hours of the year in the mid-AAEE scenario.[15] Under Rate Mix #2, which includes a residential CPP option, approximately 1 GW of peak load reduction is achievable. Under Rate Mix #3 (used in the Phase 1 analysis), we estimated a potential of 0.8 GW peak load reduction (out of approximately 40 GW net load peak). For each of the Rate Mix options, non-residential CPP rates are included, thus, load impacts from CPP are included in the results.

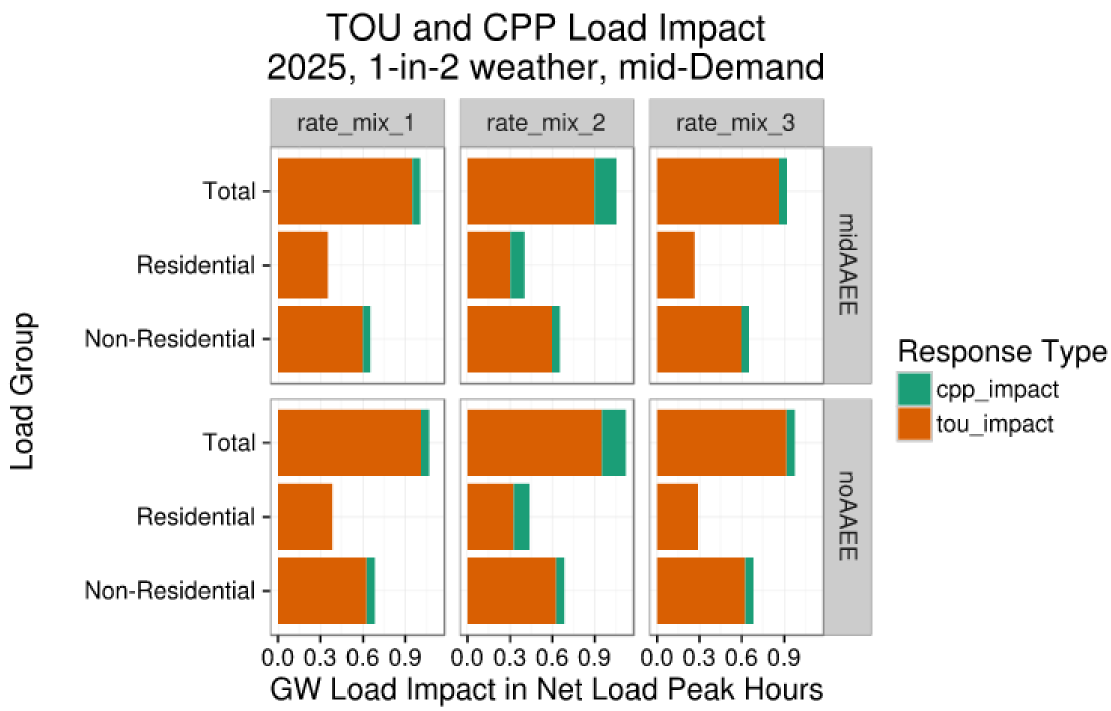


Figure 28: The Shape-as-Shed resource for 2025 under the three Rate Mixes under the two EE scenarios: no AAEE and mid-AAEE.

The Shape-as-Shift DR potential is approximately 1.8 GWh per day for 2025, indicating that significant load can be shifted throughout the day with price signals from retail rates. Figure 29 presents the results from the Shape-as-Shift analysis, where we found that each of the Rate Mixes performs equally well as a Shift service, with Rate Mix #2 (Optional CPP rate) providing slightly higher daily DR Shift results in 2025. The x-axis indicates the total GWh per day of effective shift DR provided by the various TOU/CPP rate mixes. The Shape-as-Shift DR

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[15] For CPP valuation, we assumed that 15 events occur on the days with the highest daily peaks, each lasting 4 hours, would be dispatched during the summer months, for a total of 60 hours.

resource was calculated by taking the price response load impacts from a randomly assigned (Monte Carlo) dispatch of hours in the year.

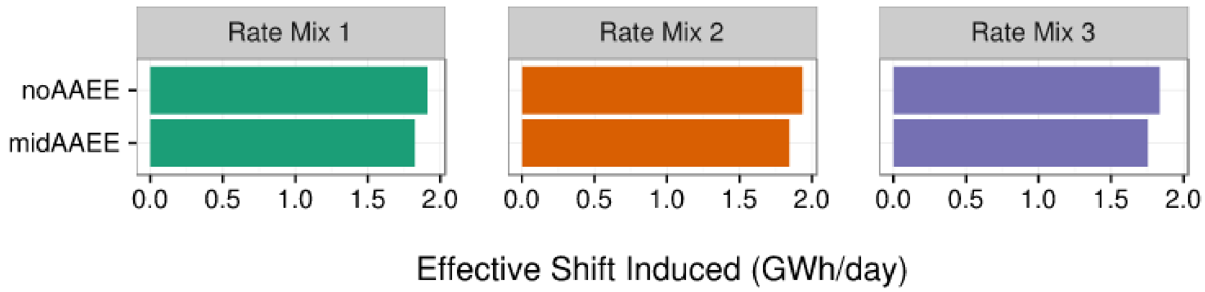

Figure 29: The Shape-as-Shift resource for 2025 under the three Rate Mixes under the two EE scenarios: no AAEE and mid-AAEE.

We estimated that the effects of TOU and CPP pricing provide the equivalent of approximately 1 GW in Shed resource and 1.8 GWh/day in Shift resource.[16] The average total daily load in 2025 is 600–700 GWh, so the Shape-Shift resource represents approximately 0.3 percent of load shifted. This is based on estimates of how "static" TOU retail pricing structure are expected to change load, and how those modifications provide service equivalent to Shed and Shift service described above. This study included modified load shapes from the effects of TOU and CPP under three mixes of rate availability and enrollment, but did not include the possible effects of additional enabling technology investment or responses from prices more closely connected with the real-time locational marginal price of electricity. With more significant investments in automatic price-responsive technology and exposure to real-time dynamic prices it could be possible to achieve a significant portion of the dispatchable Shift resource we identified using price signals as opposed to conventional dispatch. A distributed price-responsive portfolio of loads that can shift may be more cost-effective than using centralized dispatch and payments through specific supply-side markets for the Shift resource.

5.2.2. TOU and CPP Pricing Impacts

The load impacts for TOU and CPP pricing were calculated in a standalone model that predicts load impact based on a range of demographic factors for each of the rate options in the study. The combined impacts from a mix of rates (see Figure 30, Figure 31, Figure 32 and Figure 33) below show the load impacts that are the basis for estimates of the equivalent Shed and Shift DR. Note that the residential TOU rate impacts are energy neutral over the course of the year,

[16] It should be noted that CPP is available for dispatch up to 15 times per year and must be called a day in advance of a peak capacity event. Inasmuch, there is a risk of forecast error for predicting the load impacts from CPP events.

with slight load increases in the non-summer months and load reductions that are concentrated on the net load peak hours in the summer. The non-residential load impacts we included as an illustrative estimate includes a structural conservation behavior element, as was described in Christensen & Associates' report on Statewide Time-of- Use Scenario Modeling for the 2015 California Energy Commission Integrated Energy Policy Report.[17]

With different timing and price ratios, we expect that TOU prices, CPP, and other price-based strategies could be a low-cost opportunity to advanced adoption of DR technologies. As customers are exposed to price signals from dynamic pricing, we could see uptake in technologies that add convenience and control for managing their energy use. As more devices come online that are price responsive we expect deeper and more dynamic load Shifts and Sheds could be possible than we estimate in this study, since the load impacts included in our study are primarily from past studies with nominal low-cost enabling technologies.

Electric vehicles, behind the meter storage, and other new load categories could also significantly alter the dynamics of price sensitivity. Combining electricity storage, advanced controls, and retail prices that incentivize arbitrage could lead to a dynamic where significant fractions of the Shed and Shift we describe in the DR potential supply curves is achievable through retail prices alone.

There could also be other pathways to dynamic price exposure. Recent policy proposals for the CAISO markets for Proxy Demand Resources (The "ESDER 2" Second Revised Straw Proposal from September 19, 2016) indicate the possibility of bidirectional load exposure to prices. The passage below from the executive summary of that document describes how a "supply market price signal" could occur (emphasis ours):

> *"(Describing the expected dynamics of wholesale vs. retail market exposure for customers) …The end-use consumer would pay retail prices for load consumed. The ISO would settle wholesale energy at the wholesale market-clearing price, positive or negative.* ***The bid to consume load will simply be a price the bidder is willing to pay or be paid for energy and will be settled in the wholesale market through a Scheduling Coordinator independently from the retail settlement.*** *The bidder could, for example, structure a negative bid, which means the bidder expects to be paid for consumption of energy if negative bids are in the money and clear the market in certain intervals."*

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[17] Hansen, Daniel, et. al, Statewide Time-of- Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report, Christensen & Associates. December, 2015 http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207031_20151215T151300_Statewide_TimeofUse_Scenario_Modeling_for_2015_California_Energ.pdf

While supply market integration could be a pathway to price exposure, the transaction costs could be significant with additional categories of cost that would not be included in a dynamic price for consumption (e.g., scheduling coordinator fees, the loss of response from randomly withheld participants to establish a control group baseline). It is plausible that coordinated market participation through PDR could help concentrate incentives to push control technology in the market (aggregators who could profit from market participation would recruit customers and help finance and install load control). However, this supply market pathway for incentivizing control technologies could be undermined if sufficient control technology were preexisting, were installed for reasons other than DR, and/or the technologies were sufficiently valued for aesthetic, comfort, and bill reduction.

Figure 30 includes a detailed load impact estimate in the residential sector and a first-order estimate for the currently embedded (and assumed to be persistent) load impacts for non-residential sites. The plot displays a flat baseline and three Rate Mixes (described elsewhere).

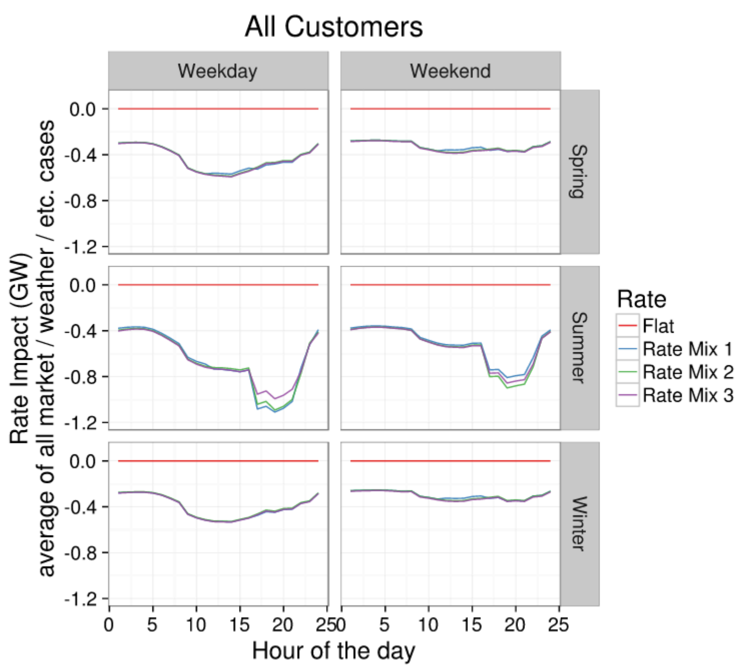


Figure 30: Average combined TOU and CPP load impacts for all customers in the CA IOU Service territories

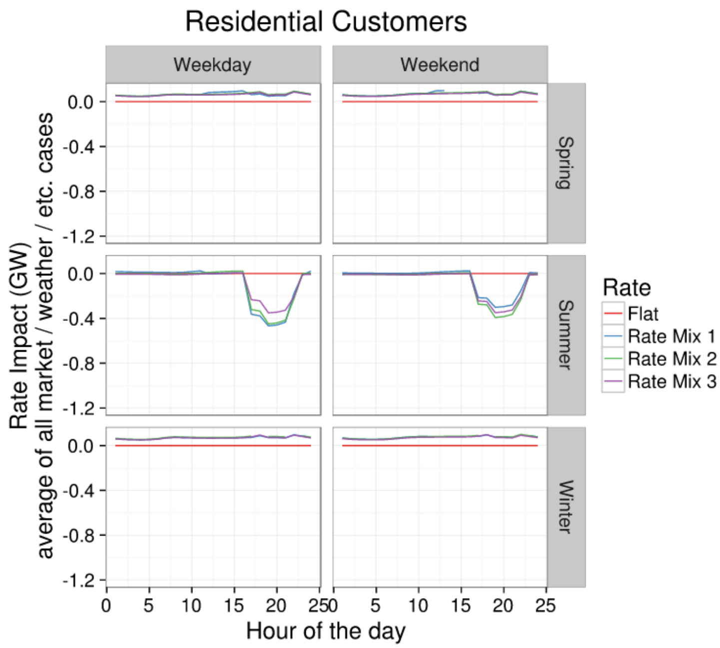


Figure 31: Average combined TOU and CPP load impacts for Residential Customers

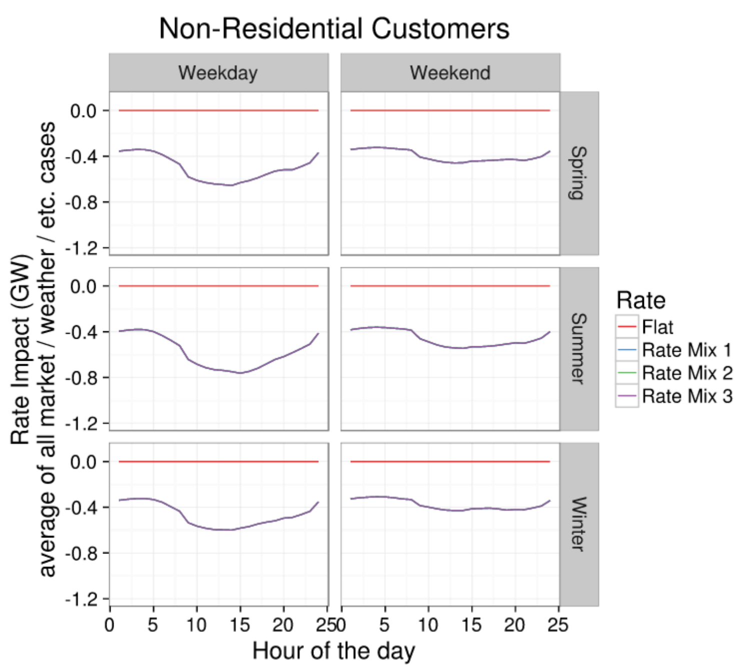


Figure 32: Average combined TOU and CPP load impacts for Non-Residential Customers

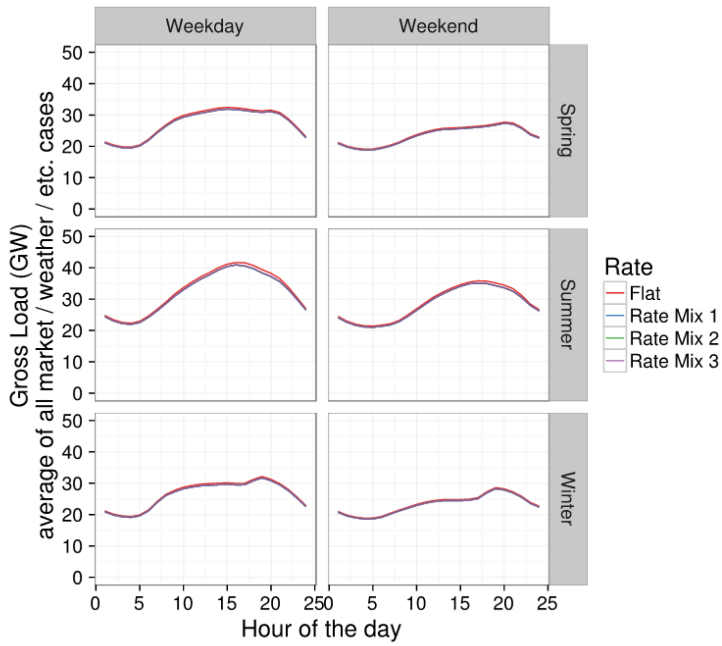


Figure 33: Average total gross load in CA IOU service areas for a flat baseline and three Rate Mixes (described elsewhere)

5.2.3. Behavioral Demand Response

Demand response from behavior changes can be dispatched or influenced through a variety of signals. In this study we model behavioral shifts and peak sheds mediated by retail price but there are other approaches that can lead to similar depth of response as well, through normative messages and third-party incentive programs. These "**behavioral demand response**" (BDR) approaches have emerged recently and leverage a range of new direct and social media channels for communicating with customers. The fast changing approaches to BDR and integration with controllable devices leads to significant uncertainty in the depth of response that is possible, and to the durability of response.

The evidence for BDR is emerging as programs are piloted, refined, and deployed. There are many anecdotal or small-sample studies and industry presentations available, and a few large-scale, controlled econometric studies that we highlight here. One study pairing communicating thermostats with BDR conducted in 2012 with ~1400 participants (700 each treatment and control) found no statistically significant effect for normative behavior appeals sent through a smart-phone application prompting users to remotely agree to energy reductions from HVAC.[18]

[18] http://www.etcc-ca.com/sites/default/files/reports/et11pge3074_opower_honeywell_final_report.pdf

A more recent large-scale assessment (10,000+ participants) did identify a response from similar normative appeals in an operational context. In that study, the average peak load reduction was 1.8-2.4 % depending on whether customers were already receiving energy reports on a consistent, regular basis (more savings for customers not already receiving a report)[19].

These findings suggest that the depth of resource for BDR is similar to retail price impacts, and that the ***details matter*** for BDR. There are differences in response between customer groups and messaging approaches and large scale samples are required to assess and verify the load impacts. The relationship between retail price and behavioral signals has not been identified, without clear evidence on whether there is potential for BDR to go beyond price or be a replacement for price-based shed. The ability of BDR to provide Shift DR has not been studied in detail, and could be a focus for future initiatives and enterprise activity as well. Any future studies or operational program impact verification should be based on careful treatment and control groups, aggregations of customers, and account for interactive effects with price to avoid double-counting.

5.3. *Shift* – Changing the Timing of Loads

We modeled Shift-type DR resources that consumed load and shed load during a 24-hour period, remained energy neutral, and were based on end uses that could plausibly move energy consumption from one hour to a different hour of the day. Loads that are available to be shifted daily can reduce system ramping needs and avoid renewable power overgeneration and curtailment. These resources included thermal loads, such as air conditioning and refrigerated warehouses, batteries, commercial and industrial batch processes, and electric vehicle charging. Shift resources, for the purpose of this analysis, are dispatchable resources, and each end use can respond to a dispatch signal that shifts the loads from one time period to another, in either a 4-hour, 8-hour, or 24-hour window. In each of these cases, it was assumed that the load within that window was split between a load take and a load shed. For example, a batch process that was shifted would be dispatched over an 8-hour window, with 4 hours of load consumption and 4 hours of load shed. In this example, a batch process that is typically scheduled to run at 5 pm would be moved to noon to consume load, and at 4 pm would be turned off to shed load for the following 4 hours, which effectively shifts the load from the later part of the day to the mid-afternoon. This resource would be available on a daily dispatch schedule. With adaptive and responsive loads that can shift energy consumption throughout the day, DR-enabled loads can support the grid by enabling better use of available renewable power and avoiding renewable

[19] Behavioral Demand Response Study - Load Impact Evaluation Report (2016) Nexant for PG&E; CALMAC ID: PGE0367.01

curtailment during hours when generation exceeds demand.

Shift service type DR captures potential loads that can be moved throughout the day. It assumes that the energy consumption is neutral over 24 hours; in other words, loads shed the same amount of energy that they take over a given window of time. Our energy neutral constraint on the Shift resource means that no "new" load is created in response, but only reshuffling. Some users may also have good reason to increase load if they have the option of low-price electricity in the middle of the day, a price elasticity dynamic that is analogous to efficiency rebound (e.g., an energy intensive industrial customer with slack in their process schedule, or a business operating a fleet of electric vehicles). This would be a "pure take" resource, and is often discussed in terms of "reverse DR", which was not considered within the scope of this study. Another simplifying assumption is that we do not model thermal losses or efficiencies resulting from shifting load.

Shift resources move load from early morning and evening hours to the midday hours of high solar output, thus reducing curtailment caused by solar overgeneration and lessening the need for imports during shoulder hours. Figure 34 shows the impact of allowing up to 20 percent of load to shift within the hour and the day on a high-curtailment day in 2025; it is an illustrative example showing a particularly high-curtailment day and how a "20 percent" Shift enables more renewable electricity to be put to use (note: 20 percent refers to a joint constraint on the maximum fraction of the daily electricity that can be shifted, and the maximum instantaneous load shed). Shift-capable loads have significant potential to reduce overgeneration during hours of high renewable generation.

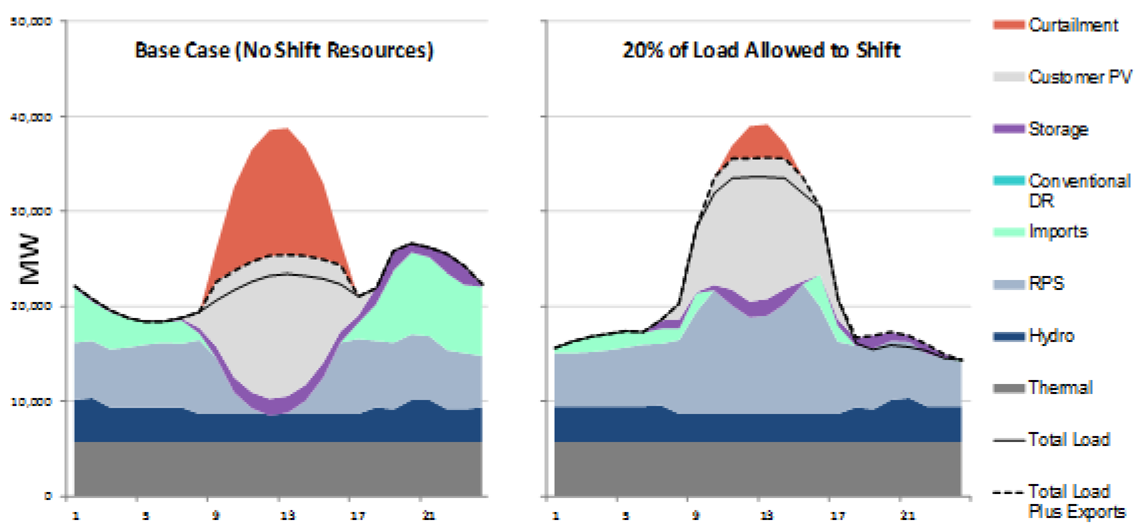


Figure 34: Dispatch impact of allowing 20% of system load to shift within each hour and within each day. Highest RESOLVE curtailment day, 2025.

For all modeled levels of Shift resource, we constrained the magnitude of Shift capable load to be a fraction of end-use load. Shift Take and Daily Shift constraints were defined as a fraction of daily load, while Shift Shed was defined as a fraction of the highest load hour in each day. Due to these differences in defining the constraints, we set the Shift Shed fraction to be twice the Shift Take and Daily Shift fractions. The three parameters are shown on the x-axis of the Results charts (e.g., Figure 35 and Figure 36). A 10 percent Shift case, for example, means hourly load can be increased to 10 percent above the maximum hour's load, and 10 percent of the load within the day can be shifted between hours. This is illustrated in Figure 35.

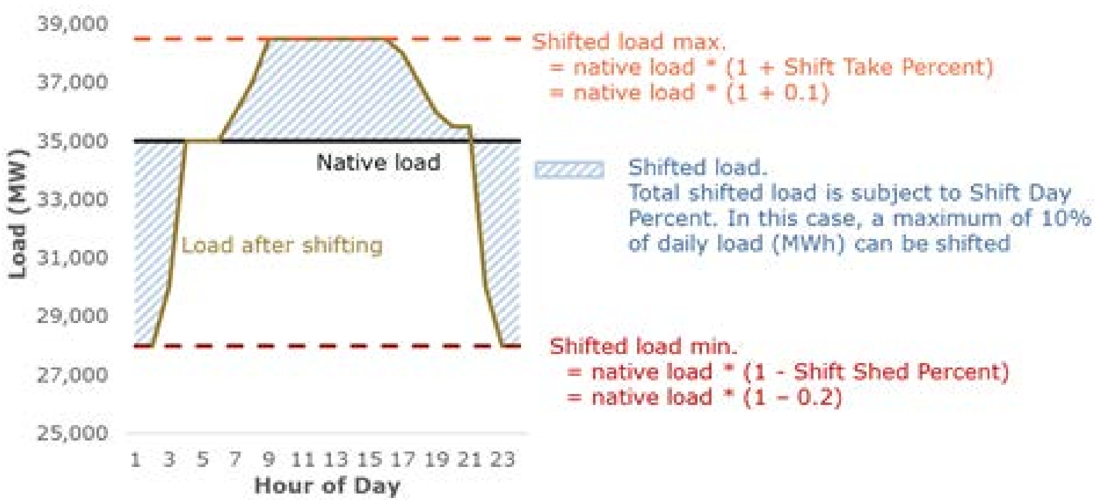


Figure 35: Illustration of 10% Shift case (the native load is shown as flat across the day to lower complexity for this illustration only).

The ability of Shift resources to "soak up" curtailment is highest for the first megawatt-hour shifted, and reduces as more Shift resources are added and the need for curtailment falls, as shown in Figure 36. The Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis represents the percentage of daily and hourly load that is shifted, while the y-axis presents the annual GWh of renewable curtailment.

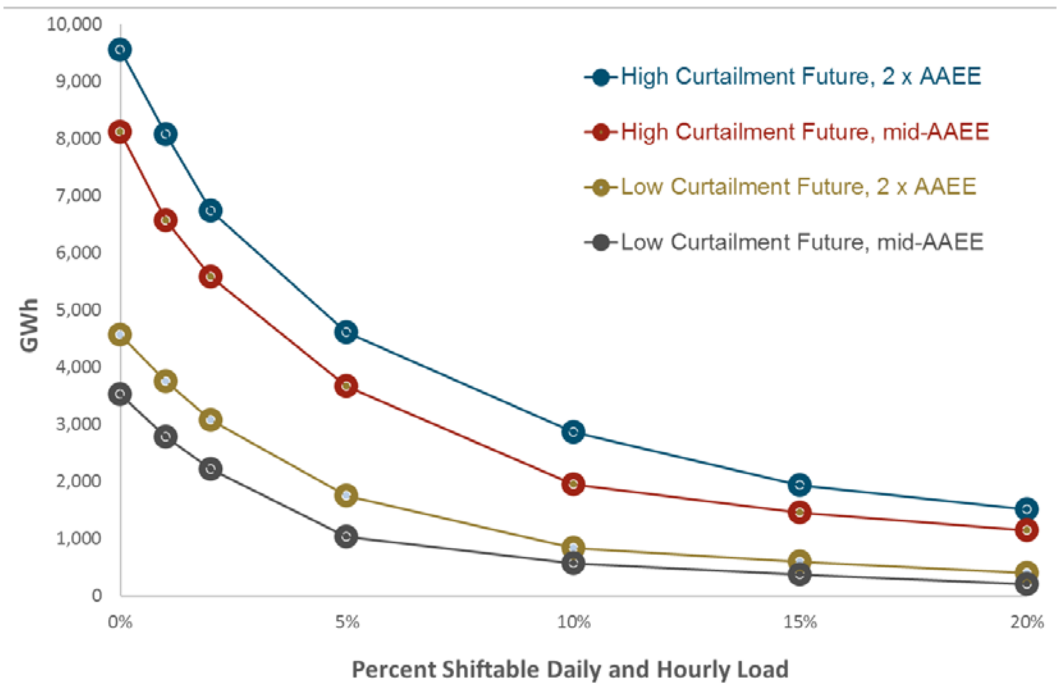


Figure 36: Annual curtailment by percent of "shiftable" load, 2025.

Shift resources are estimated to provide up to $678 million ($2015) in savings to the CAISO system in 2025, with the greatest marginal savings coming from the first increment of shifted load. It should be noted that while there is high potential market savings from Shift resources, this doesn't equate with implied cost-competitive market size. In other words, the estimated market savings reflects value to the grid, but not necessarily what is most cost effective. In section 5.3.1, we evaluate the cost competitiveness of the Shift service type by inferring the market size based on the intersection of the supply and demand curves. As shown in Figure 37, each incremental megawatt-hour of Shift resource avoids curtailment at a diminishing rate. The Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis represents the percentage of daily and hourly load that is shifted, while the y-axis presents the savings to the system in millions of dollars (2015). Because each incremental megawatt-hour of shift avoids less curtailment, each incremental megawatt-hour of shift generates less savings in two ways. First, each incremental shifted megawatt-hour replaces less gas generation with zero marginal cost renewable generation from curtailment reduction, yielding less fuel and O&M savings. Second, avoiding curtailment leads to a reduction in RPS and storage build, because a higher fraction of delivered renewables means less overbuild and storage are needed to meet the RPS. This means that as each incremental megawatt-hour shifted avoids less curtailment, it also avoids less RPS-related capacity build.

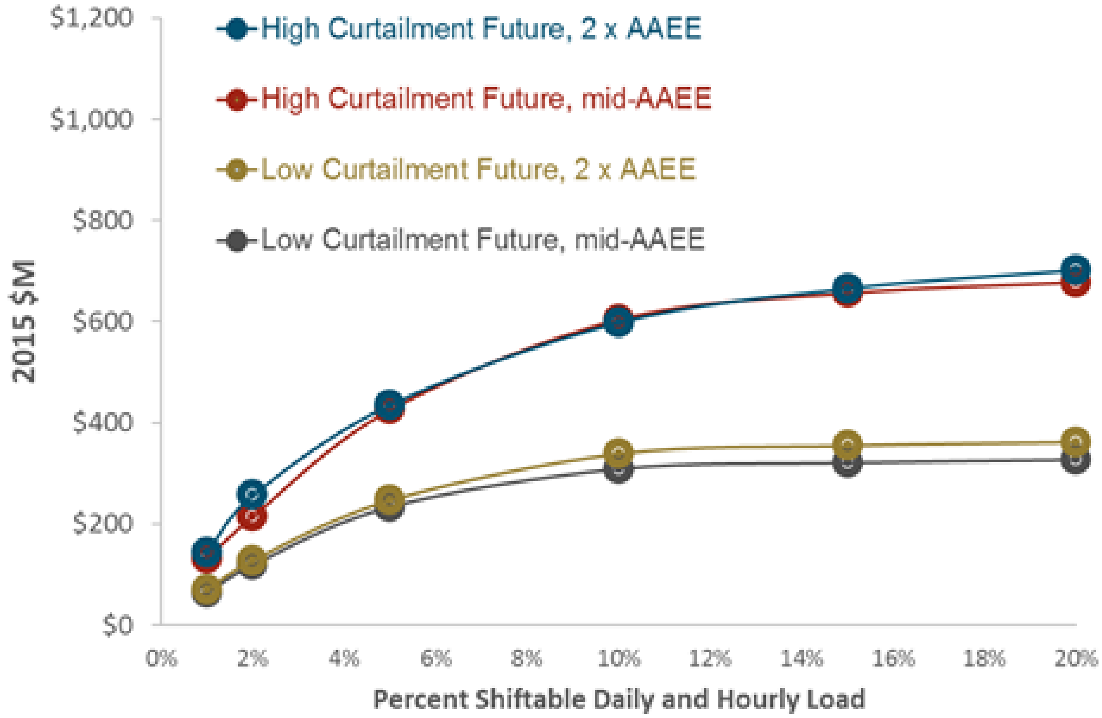


Figure 37: Total CAISO System savings from Shift resources, 2025.

RESOLVE estimated the number of megawatt-hours shifted in each year that minimizes costs to the CAISO over the 2016–2030 horizon. These megawatt-hour values can be used to create a "demand curve" that shows, at each incremental percent of shiftable load, the savings available to the CAISO per megawatt-hour of Shift resource made available. As shown by the blue curve in Figure 38, The Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis represents the percentage of daily and hourly load that is shifted, while the y-axis presents the marginal $/MWh savings. Shift resources save the CAISO system $67 per MWh shifted in 2025 when only one percent of load is shiftable (under the High-Curtailment future, double the AAEE scenario). When 20 percent of load is shiftable, the final megawatt-hour of shift saves only $15/MWh. These values drop to $31 and $5, respectively, for the Low-Curtailment future, mid-AAEE scenario.

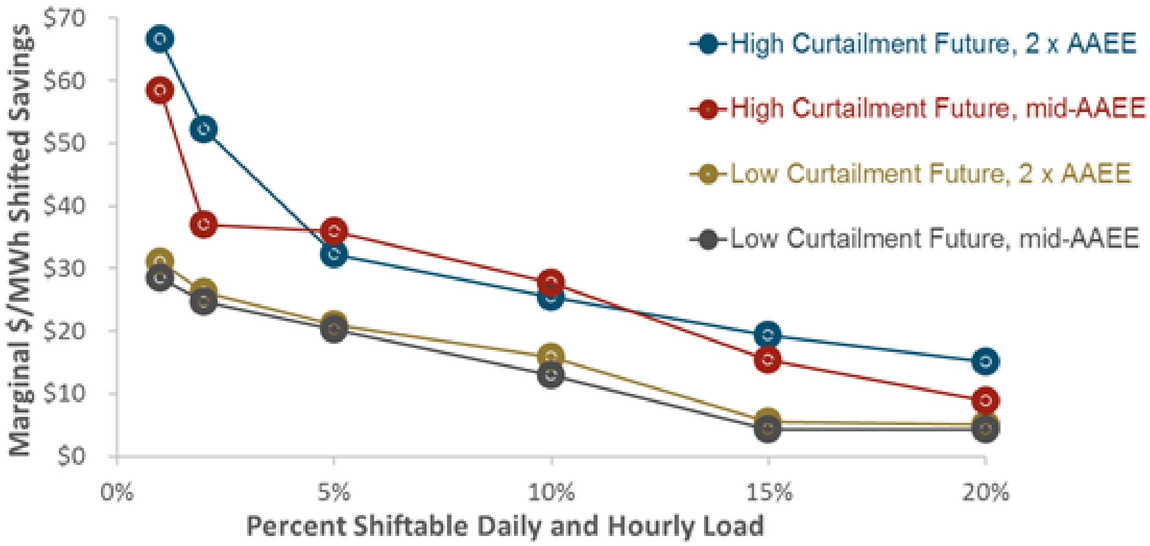


Figure 38: Marginal savings to the CAISO system per MWh shifted.

As shown in Figure 39, the savings from Shift resources increase at all penetration levels as we move closer to 2030. Recall that savings from DR assessed over the entire 2016–2030 period were allocated to individual years using the relative percentage of base case curtailment in each year. RESOLVE estimated increasing curtailment as we moved closer to 2030 and the assumed 50 percent RPS.

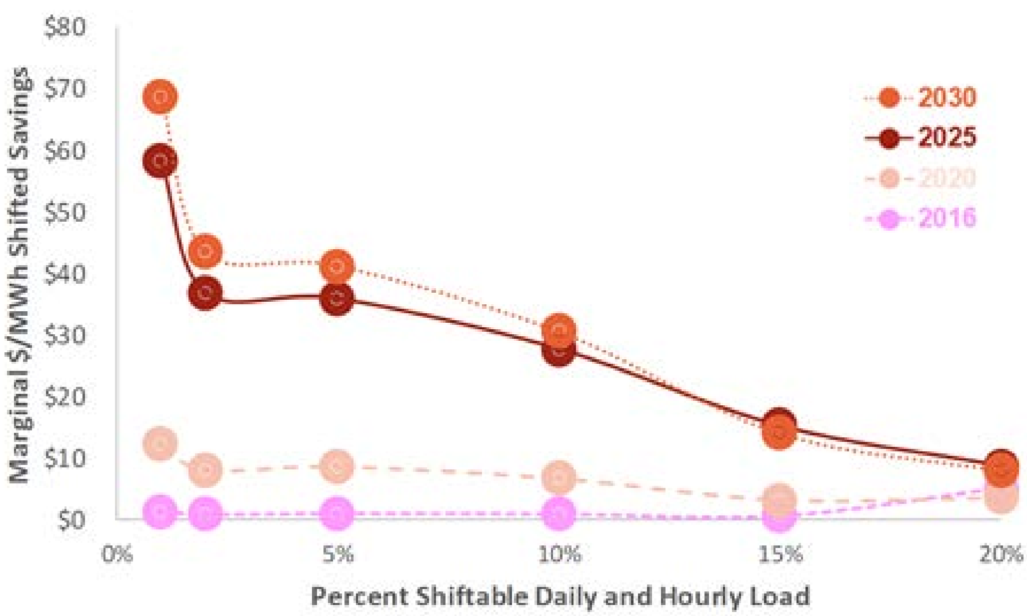


Figure 39: Marginal savings per MWh shifted, by year. High-Curtailment future, mid-AAEE scenario.

5.3.1. Valuing Shift Service Type DR with Supply Curves and Levelized Demand Curves

Shift resources have a high value to the grid, and our Shift technology cost and performance analysis indicates a significant opportunity to provide service, with a large resource at costs that are lower than the benefits. In each of the graphics provided below, we introduce the supply curves for the Shift resource and compare them to the levelized value of service; we note that the levelized costs and available cumulative DR units are reported in terms of kilowatt-hours and gigawatt-hours, respectively. The units reflect that Shift is an energy resource, as opposed to Shed and Shimmy resources, which are measured in kilowatts-year of effective capacity. Subsequent figures show average daily resource availability on the x-axis and the leveled costs per kilowatt-hour reported on an annual basis on the y-axis.

Figure 40 summarizes the main Shift findings. In 2020, only approximately 2.5 GWh per day is cost-effective—approximately 0.5 percent of the load. The RESOLVE modeling suggested the levelized value curve is relatively low in that year, close to $20/kWh shifted in 2020. However, by 2025, the value of Shift DR resources was shown to increase as more renewables are built to satisfy the 40 percent RPS requirements. The potential was shown to increase further with continuing cost reductions for Shift. Our analysis suggests that an estimated 10–20 GWh of daily Shift DR are cost competitive in 2025 if the automation technology is paid for both with site-level services ("co-benefits") and through revenue or other incentive pathways reflecting the value of Shift to the system. This results in an equilibrium price of $20–$40/kWh-year from system benefits. The colors in the lines (**top**) and bars (**bottom**) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather years and the solid lines are 1-in-10 weather years. The Low-Curtailment case (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines represent the levelized demand curves. The equilibrium price is at the intersection of the levelized demand curves and the supply curves. All of the estimates for supply Shed DR are shifted based on the contributions of TOU/CPP rates, which is indicated in **BLUE**. Case: Year 2025, Rate Mix #3, mid-AAEE trajectory. Figure 41 shows how the cost-effective potential (and implied market size) changes between 2020 and 2025, for the low- and high-curtailment cases. Significant growth is observed in all cases between 2020 and 2025, with an implied cost competitive Shift DR market size of $100–$400M/year by 2025.

While modest quantities of cost-effective resources are expected in 2020 with a full-cost accounting framework, Figure 42 shows how including co-benefits for both site-level and distribution system benefits could change the equation by 2025. The DR potential increases significantly when sources of revenue and co-benefits are included in the supply curves, (i.e., reduce the costs of the DR technologies).

In Figure 42, beginning with the upper left quadrant, going clockwise: Supply curves with unadjusted total costs, net total costs with ISO revenue, net revenues with site-level co-benefits (i.e., the same as Figure 40: (top) Shift DR potential supply curve results compared to a levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.), and net revenue with site and distribution system benefits incorporated into Shed supply curves. Each quadrant depicts the supply curve estimates developed for the Base, BAU, Medium, and High scenarios.

Once we account for these benefits (assuming that some Shift DR is also optimally located in the distribution system so that it avoids building new infrastructure to handle load growth, and that some resources provide site-level benefits), the increase in Shift DR that is cost competitive is significant, resulting in more than 25 GWh per day in 2025, under the high curtailment and high potential scenarios.

With the full stack of integrated benefits, there is significant potential to develop technology by 2020 and continue to 2025, when system-level needs become more binding. This suggests a possible ramp-up role for “distributed resource planning” to use site and city-scale services to help scale up regional flexibility in advance of system-level need.

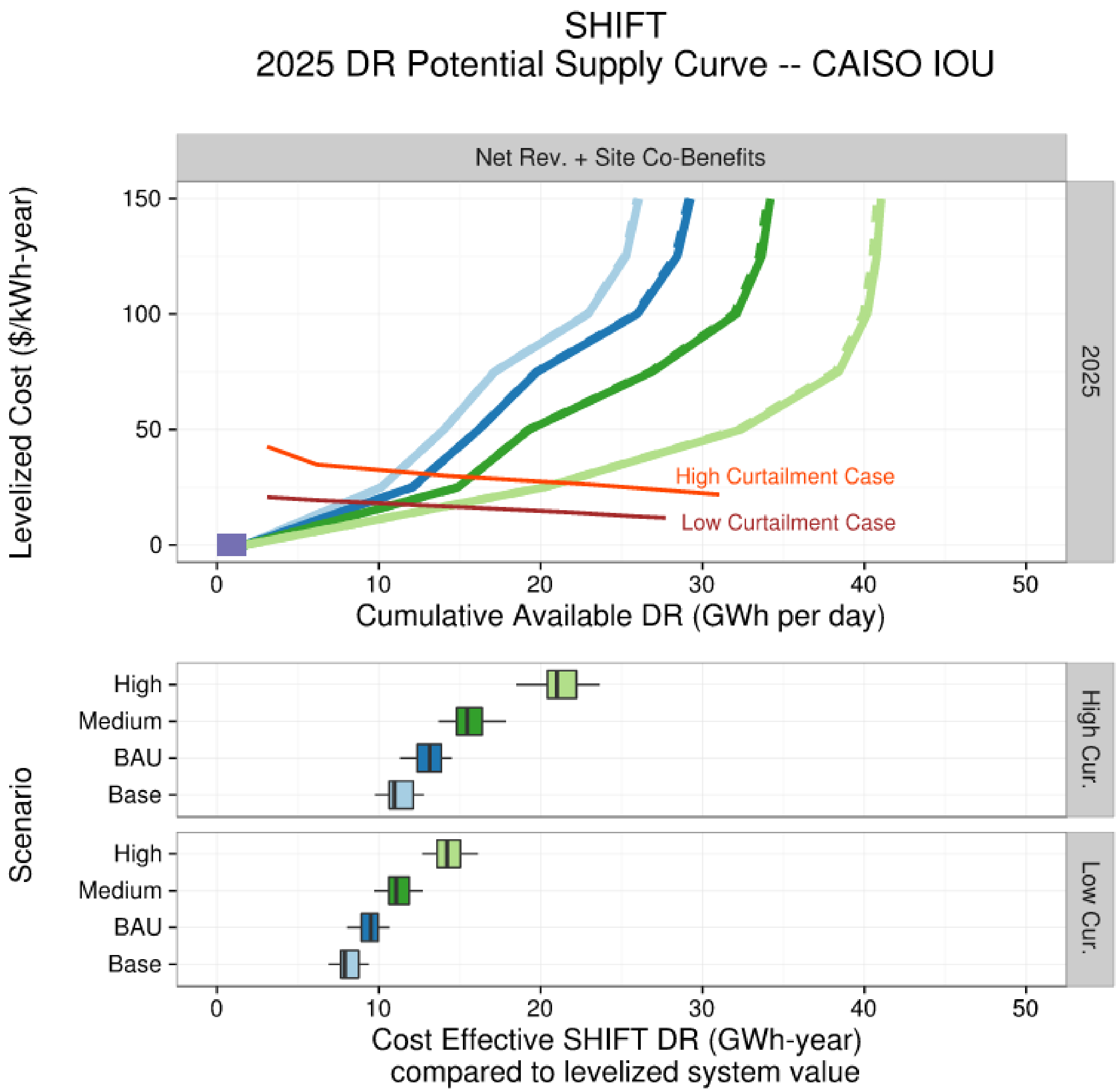
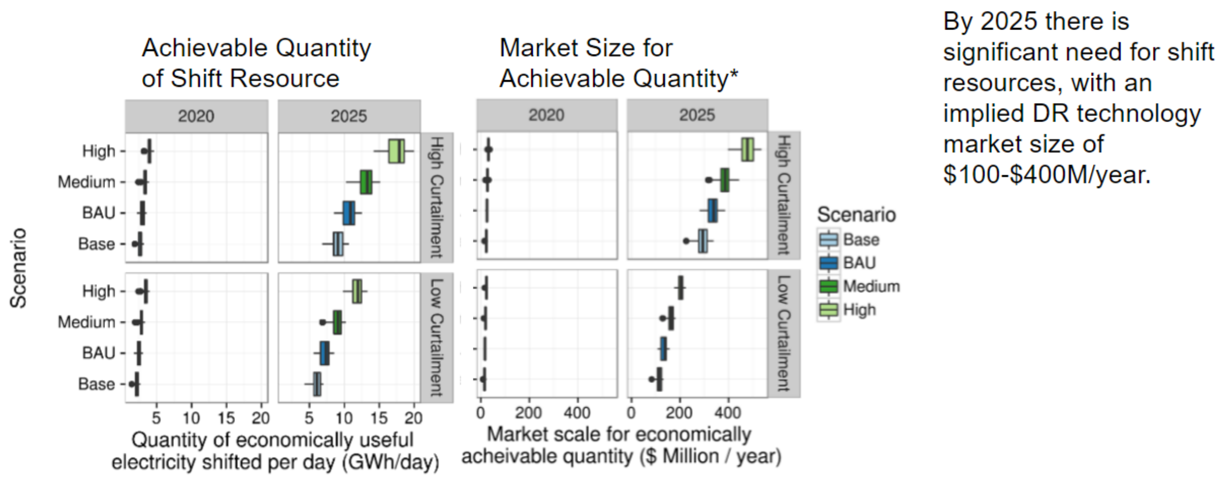


Figure 40: (top) Shift DR potential supply curve results compared to a levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.



*est. with (quantity/year x equilibrium price)

Figure 41: Box and whisker charts of Shift DR resource quantity (left) and approximate market size (right) for both 2020 and 2025.

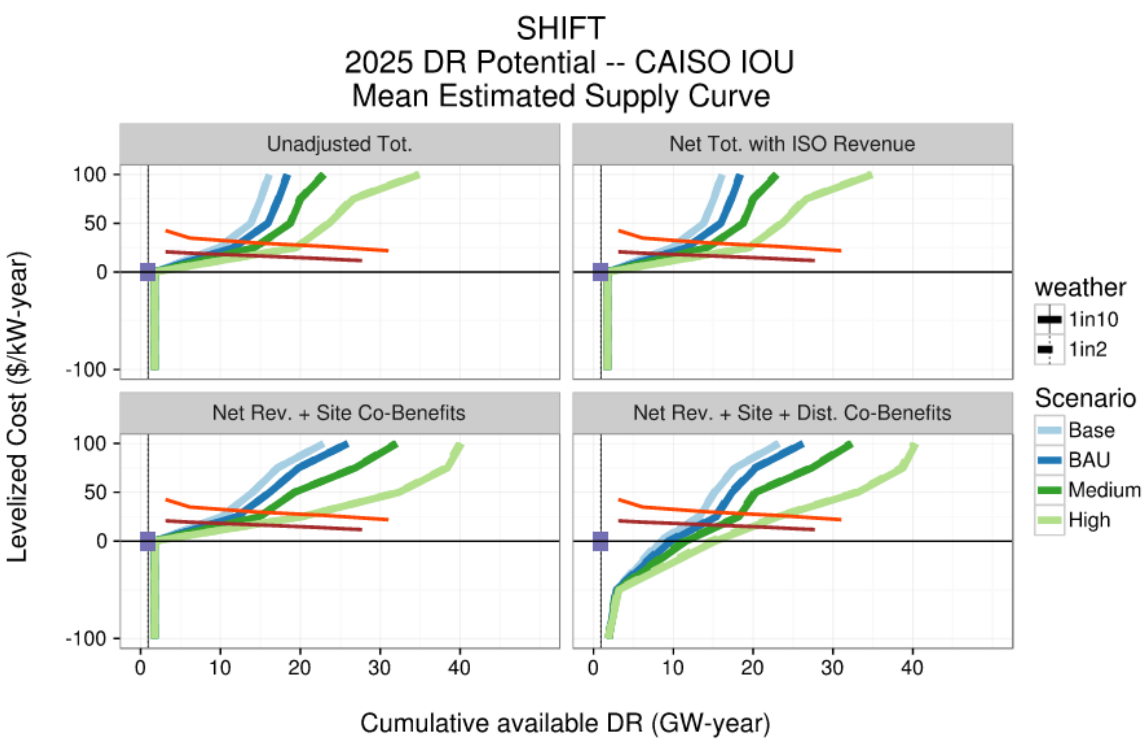


Figure 42: 2025 Shift-type DR potential supply curves with various estimates of revenue streams contributing to the economic efficiency of DR technology costs.

In Table 10 and Table 11 below, we provide the cost competitive prices and quantity of Shift DR from the DR Futures supply curves and the RESOLVE levelized demand curves, and represent the price at the intersection of each curve. The price and quantity reflects the levelized cost and value to the grid; in other words, the price for each DR unit (MW or MWh) is economical when compared to the costs of other generation resources. The costs and quantities for each service type are segmented by percentiles that capture the variance around the demand and supply curves' intersection.

Table 10: Levelized Price and Quantity of Cost Competitive Shift DR by Percentile (Low Curtailment Scenario – Medium DR Scenario)

Shift DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue Co-Benefits + Distribution System Payments
25th Percentile Price per kWh ($)	$18	$18	$18	$16
25th Percentile Quantity (MWh)	8,489	8,489	8,874	13,322
50th Percentile Price per kWh ($)	$18	$18	$18	$16
50th Percentile Quantity (MWh)	9,018	9,018	9,324	13,760
Mean Price per kWh ($)	$18	$18	$18	$16
Mean Quantity (MWh)	9,053	9,053	9,426	13,935
75th Percentile Price per kWh ($)	$18	$18	$18	$17
75th Percentile Quantity (MWh)	9,632	9,632	10,128	14,618

Table 11: Levelized Price and Quantity of Cost Competitive Shift DR by Percentile (High Curtailment Scenario – Medium DR Scenario)

Shift DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue Co-Benefits + Distribution System Payments
25th Percentile Price per kWh ($)	$29	$29	$28	$26
25th Percentile Quantity (MWh)	12,513	12,513	13,061	15,625
50th Percentile Price per kWh ($)	$29	$29	$29	$27
50th Percentile Quantity (MWh)	13,320	13,320	13,708	16,390
Mean Price per kWh ($)	$29	$29	$29	$27
Mean Quantity (MWh)	13,336	13,336	13,898	16,486
75th Percentile Price per kWh ($)	$30	$30	$30	$28
75th Percentile Quantity (MWh)	14,174	14,174	14,639	17,370

Table 12 below summarizes the expected Shift DR potential by utility, by year. It shows the breakdown of expected potential by utility service area, and the implications of the portfolio benefits of multiple value streams (through cost accounting framework modifications).

Table 12: Shift potential (MWh-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

	2020			2025		
Cost Framework	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Unadjusted Tot.	1400	1800	94	5800	7100	430
Net Tot. with ISO Revenue	1400	1800	94	5800	7100	430
Net Rev. + Site Co-Benefits	1400	1900	97	6000	7500	450
Net Rev. + Site + Dist. Co-Benefits	4300	5000	240	7400	8500	570

5.3.2. Shift Technology

Shift resources come from a variety of technology options, with large shares from HVAC and process scheduling. Figure 43 provides a breakdown of the Shift DR potential in 2025 at a price level of $50 / kWh – approximately the upper end of the value we identified to the grid – disaggregated by IOU service territory and end use. Industrial process loads provide approximately 4 GWh-year to PG&E, and nearly 5 GWh-year to SCE, with agricultural pumping providing 1.7 GWh-year and 0.5 GWh-year to PG&E and SCE, respectively. Commercial HVAC is another large contributor, with more than 5 GWh-year between the three IOUs. It is notable that very little resource comes from behind-the-meter batteries in the case without co-benefits, suggesting that load control is more cost competitive than electrochemical storage for the first several gigawatt-hours shifted per day.

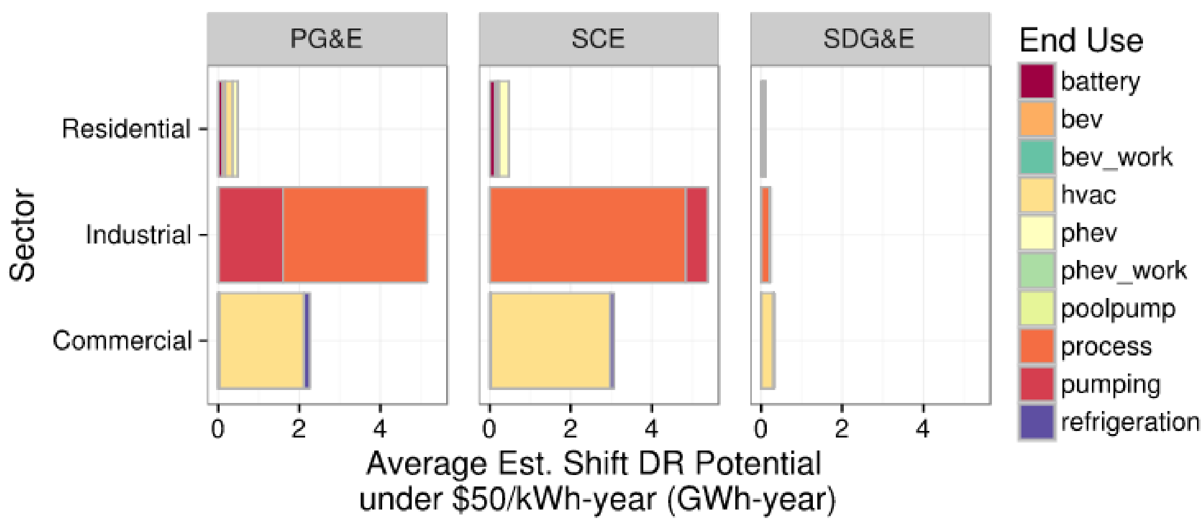


Figure 43: 2025 Shift DR potential by IOU service territory and end-use contributions under $50/kWh-year, mid-AAEE, 1-in-2 weather year, Medium scenario.

While behind-the-meter storage does not feature prominently in our estimates at $50/kWh-year, Figure 44 below shows that at costs of $100/kWh and up the contributions of behind-the-meter storage could be substantial. The contributions of each sector are grouped, with boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation. Another way to read this is that if there are much steeper declines in the cost of storage (and/or additional value streams accessible to storage) then energy storage technology could be a significant contributor to the Shift resource. The results also suggest that electric vehicle charging could be an important resource with more aggressive cost and/or business model advances.

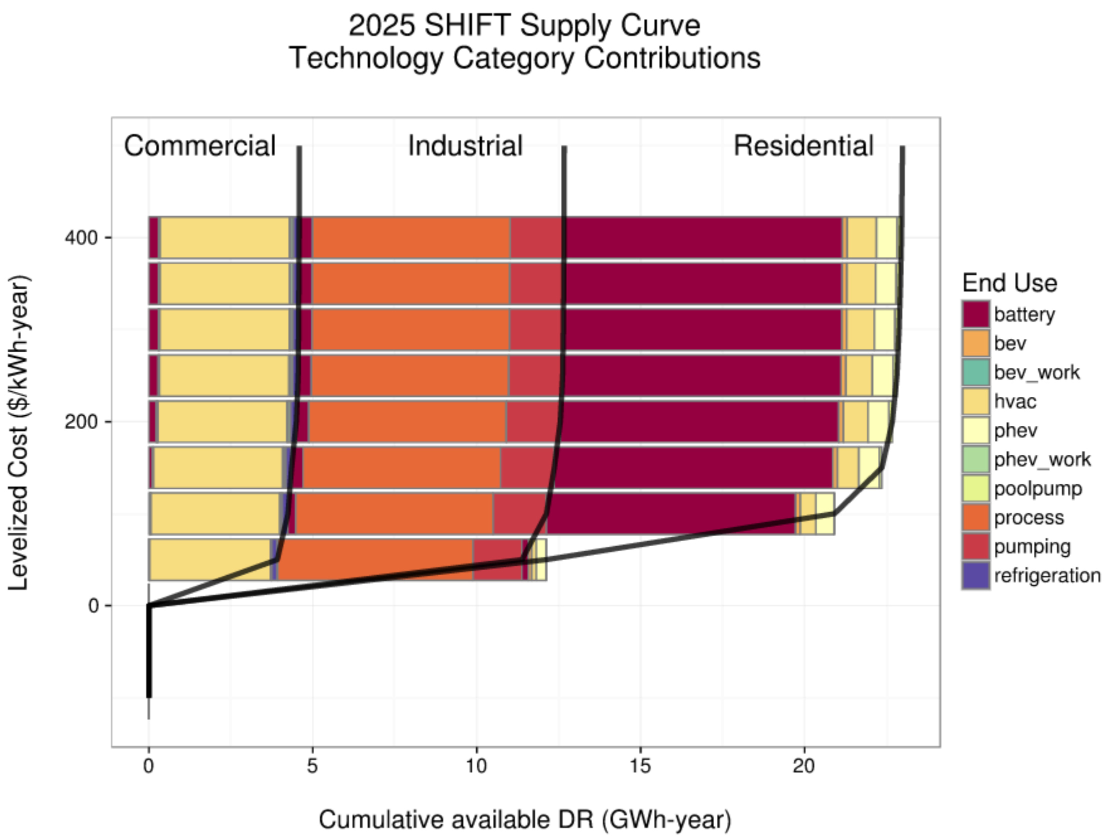


Figure 44: Shift DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

For Shift and other resources, our analysis of potential was based on a large number of possible supply curves, each defined by a particular scenario with random variation in the DR technology and cost introduced. Figure 45 shows the full set of supply curve options included in the analysis. The box plots displayed at the bottom of Figure 40 are a representation of this uncertainty in results, showing the range in intersection points among the many supply curves shown in plots like Figure 45. The x-axis depicts mean available GWh/day and the y-axis represents the levelized costs in $/kWh-yr for the resource. This supply curve shows the unadjusted total costs for the service type under the Base, BAU, Medium and High scenarios, and includes the results from Monte Carlo analysis, illustrating the uncertainty bounds of the estimates for the resource. These are the full set of “stochastic” supply cures for Shift resource, and we focus on the mean supply curve for displaying many graphics below.

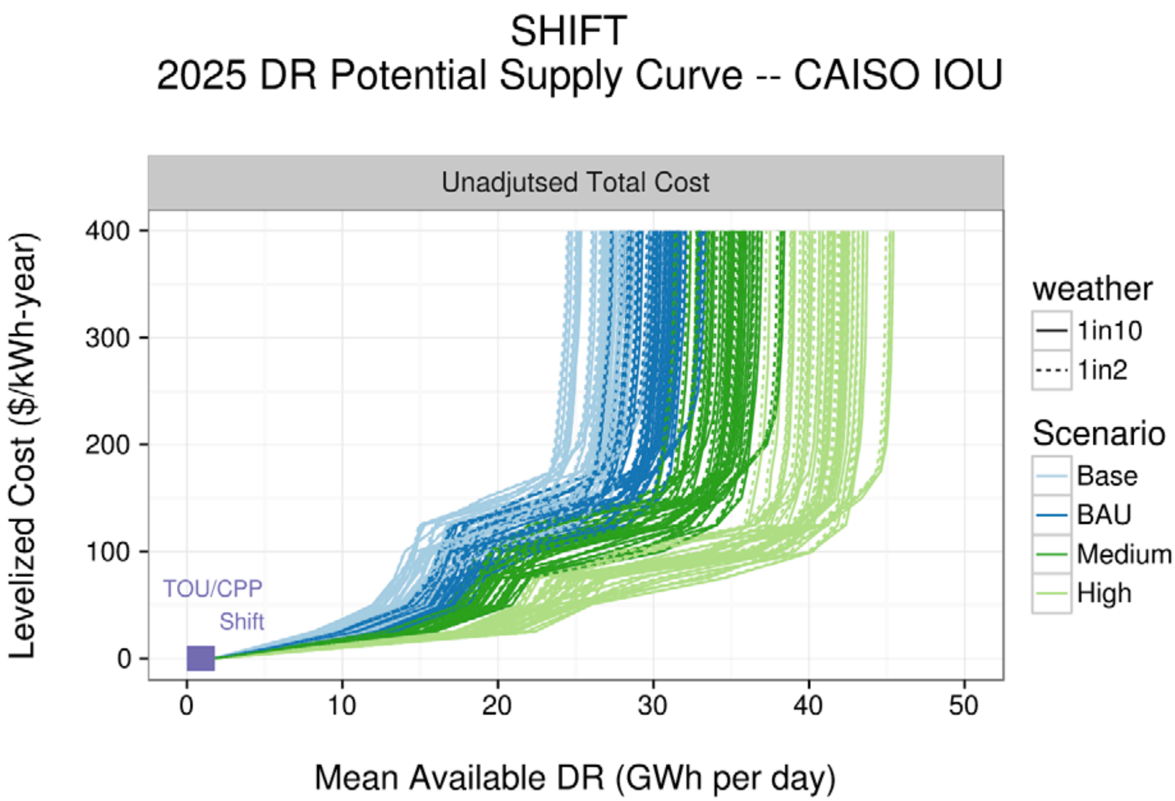


Figure 45: 2025 Shift service type DR potential with conventional TOU/CPP providing 1.8 GWh/day of Shift resource.

5.3.3. Price-Responsive *Shift* Pathways to Market Participation

The Shift service type resource is by far the largest opportunity we identified for DR to provide system-level value (up to ~$700 million/year). This value is derived from dispatchable daily energy shifts enabled with advanced control technology; economically effective DR amounts to up to ~10 percent of daily energy shifted in 2025 (for the high-curtailment, mid-AAEE scenario). Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration, and prevent the need to overbuild renewables capacity to meet clean energy goals.

There remain significant market and regulatory barriers to capturing this value, as no market mechanism currently exists for compensating services like Shift DR. These services are technology-driven and responsive to hourly and daily changes in the needs of the system. When considering potential revenue streams from the supply-side market, Shift *potentially* could earn revenues from energy, capacity, AS and flexible capacity markets, but those markets are not

currently organized to compensate a service like Shift DR. Shift resources would be dispatched on most days in the energy market, as their value is driven by California's daily solar generation.

Identifying appropriate and accurate baselines against which to compare response when there are not days *without* Shift also presents a significant challenge. Baseline estimation already poses a barrier to measurement and compensation of Peak Shed DR resources that are only dispatched a handful of times a year. It remains unclear whether compliance obligations would need to be restructured to qualify aggregations of shiftable loads to allow Shift-type resources to participate in flexible capacity markets.

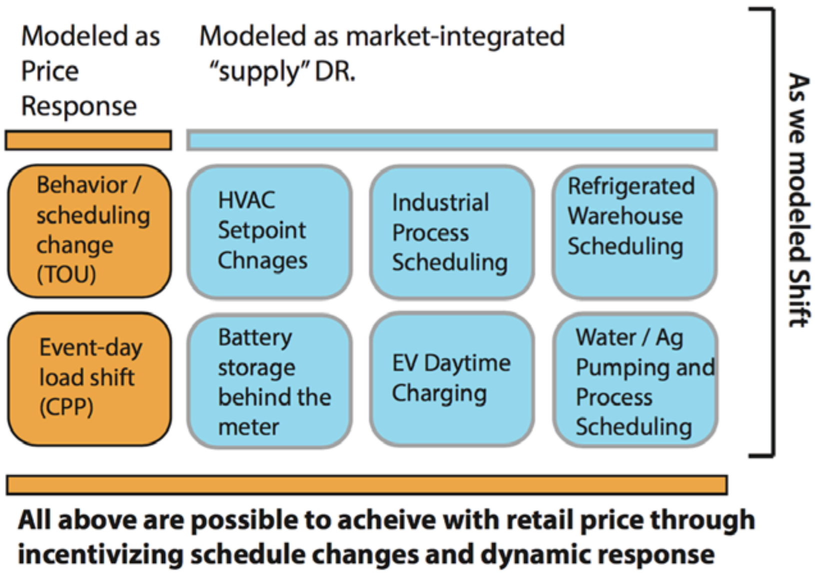


Figure 46: Categories of Shift resources in our modeling framework.

Because of these significant challenges to integration in the ISO-dispatched supply market, it makes sense to apply effort towards better understanding how Shift-type resources could be handled through the retail market through pricing programs paired with automated DR controls. This comes with its own challenges around incentivizing investment in control technology and customer adoption, but could accomplish the same fundamental dynamics with a more transparent pathway to market integration and lower transactions costs.

There have already been successful pilots of this approach to load-specific price response with electric vehicle charging in San Diego. The pilot showed that combining even simple control technology (user-controlled timers) with an aggressive price schedule can induce significant

shifts in charging profiles.[20] Additional pilots and study could help uncover the most cost-effective and reliable pathways for developing Shift resource.

A key concept to keep in mind for Shift market and technology development is that it is a resource with an energy-based, cumulative value, rather than a power-based capacity value, placing it in a separate category from conventional Shed DR. Unlike with Shed, where the value of a resource derives strongly from its reliability and usefulness in real-time dispatch, the value of Shift resources come from multi-hour changes and accumulate through the years. As more renewable electricity that would otherwise be curtailed is captured, the value increases.

The first order contours of the ideal Shift profile appear to be relatively simple and predictable (use less in the night and more in the day), suggests that there is a strong potential role for permanent load shifting and rescheduling efforts. In addition, notification with day-ahead price schedules could let loads with day-to-day flexibility optimize operation further. The current stock of conventional DR technology is fast enough to respond to these day-ahead signals, and may present a low-cost alternative to enabling new DR sites.

5.4. Targeted Load Curtailment with *Shed*

Conventional DR has typically been procured and dispatched to decrease systemwide load during peak day events. Demand response is dispatched to offset operation of peaking power plants, relieve transmission system congestion, reduce pressure to invest in conventional generation for serving peak load, and respond to contingency events. However, system needs are quickly changing. The combination of widespread expansion in the renewable generation fleet and aggressive energy-efficiency policies that reduce load growth have led to an "overcapacity" condition on the system level in which there is little value for Shed in normal system operations—there are more than enough power plants to carry the typical net load today and well into the future. This suggests that the core goal of conventional DR and many other efforts aimed at cost-effectively maintaining service during peak demand periods should be rethought or restructured. Targeting non-critical loads that can be reliably curtailed in times of critical need, can serve the local transmission pockets' and distribution system needs.

"Shed" resources as modeled in this study are those that provide the conventional form of downward DR, by which load is reduced to lower peak demands on the grid. California has a long history of implementing DR programs to encourage load reduction. The California Energy Action Plan (EAP) issued in April 2003 placed energy efficiency and demand response as

[20] SDG&E Electric Vehicle-Grid Integration Pilot Program Semi-Annual Report, Sept. 2016 https://www.sdge.com/sites/default/files/documents/1699906766/VGI%20Semi%20Annual%20Report%202016.pdf?nid=19236

preferred resources and set a goal of meeting 5 percent of peak loads with demand response by 2007.[21] Building on the avoided cost framework developed for distributed energy resources, E3 supported the CPUC in developing DR cost-effectiveness protocols first adopted in 2010 and updated in 2015.[22] As for distributed energy resources in general, the protocols include several categories of benefits or avoided costs, including energy, system capacity value, transmission and distribution deferral, GHG emissions, ancillary services, losses and an RPS adder.

By far, the largest value for DR in existing DR cost-effectiveness protocols is the generation capacity value. The second is deferred transmission and distribution upgrades, though to-date the vast majority of DR has been called based on system rather than local distribution conditions. The DR cost-effectiveness protocols include several adjustment factors to properly evaluate the capacity value of DR resources to the traditional supply side resource of a combustion turbine. The adjustment factors are designed to account for limitations on DR as a resource, including advance notification requirements and the maximum frequency and duration of calls permitted.

There are, however, still significant opportunities for Shed DR to provide value to the grid. First is local capacity. While there is a surplus on the system level, the local availability of generation is a binding constraint in some transmission-constrained areas. The Los Angeles Basin, San Diego and Ventura County all currently experience local capacity constraints that must be met either with costly local generators (which produce emissions in densely populated areas), fixed energy storage, or demand response and other IDSM approaches. About half of the statewide Shed capacity is located in these transmission-constrained regions, and our estimates suggest resources dispatched locally can respond quickly enough to meet relatively fast dispatch needs compared to systemwide peak shedding.

Our findings suggest that Shed DR resources could provide ~4.2 GW of RA credit capacity in 2025 under the 1-in-2 weather, mid-AAEE, Rate Mix #3 scenario utilizing the price referent of $200/kW-yr. The Shape-shed DR results are additive and provide an additional 1 GW of reduction (labeled “TOU/CPP”), for a total of 5.2 GW.

Below we present supply curves estimating Shed DR potential. This conventional DR is dispatched to decrease load during a peak day event, meant to either offset the need for peaking power plants or to respond to contingencies. The units of analysis are as follows:

- **Quantity:** GW-year, the average amount of load shed during the top 250 net load hours

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[21] The document “California Demand Response: A Vision for the Future (2002–2007)” is included in D.03-06-032 as Attachment A. http://www.caiso.com/1f5d/1f5dafda37730.pdf

[22] See CPUC Decision D 10-12-024, Rulemaking R 13-09-011 and Decision D. 15-11-042.

of the year

- **Cost:** $/kW-year, the levelized cost of providing 1 kW of peak load shed throughout the year

Figure 47 presents the estimates for 2020 Shed DR potential with net revenues (i.e., market revenues applied to the supply curve that reduce the cost of DR in hours when DR participates in the supply markets). The figure includes the Price Referent of $200/kW-yr, as discussed in the Economic Valuation section. The supply curve estimates developed for the Base, BAU, Medium, and High scenarios and a 1-in-2 and 1-in-10 weather year. Estimates include approximately 1 GW of Shape-shed potential from TOU and CPP.

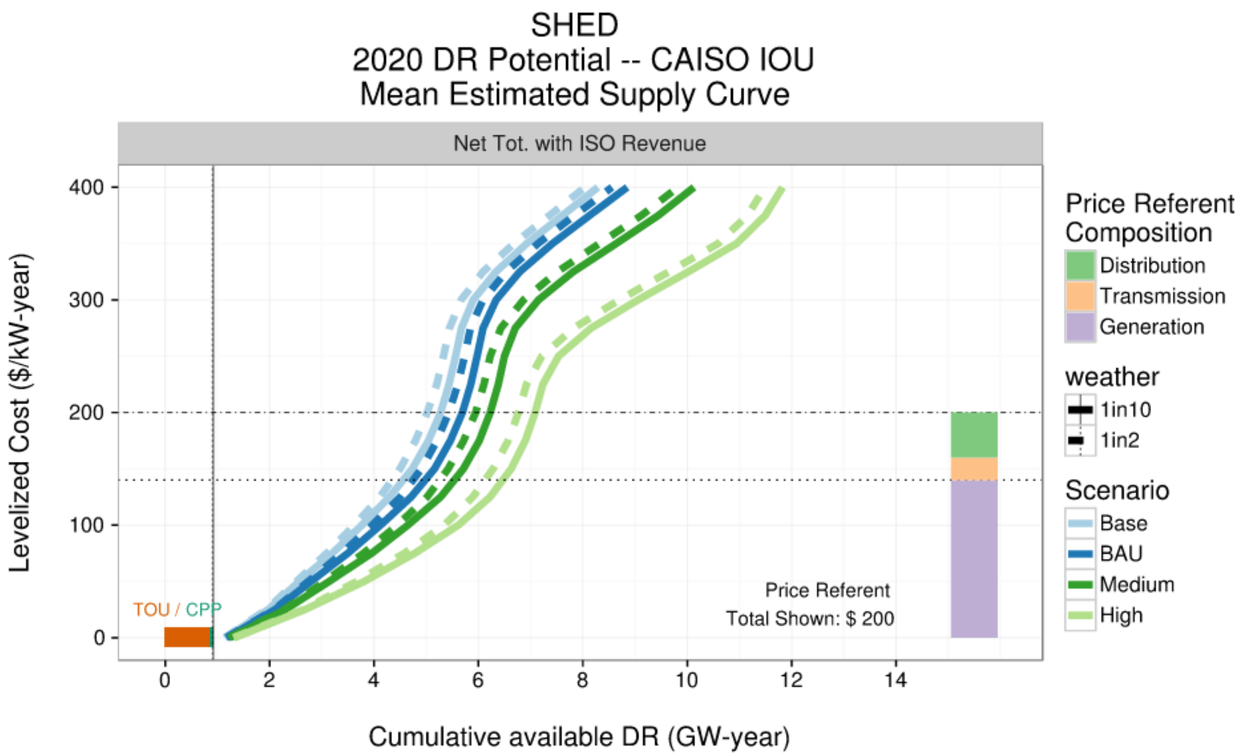

Figure 47: 2020 Shed DR potential supply curve including market revenue and the $200/kW-yr price referent.

5.4.1. Site-level Energy Management

Investments in DR technologies can often be bundled with energy-efficiency upgrades and energy management/building management systems, and provide cost efficiencies when procuring DR and EE technologies simultaneously. We capture these efficiencies as "co-benefit streams."

Bundling EE, DR and other DER technologies can improve the cost effectiveness for customers and program administrators, as well improving the operation of end uses at the service premise. Program administrators that can utilize funding from various customer service program budgets to create optimal energy service solutions can improve energy management for customers and the distribution system.

Enabling a building or end use with the control and communication systems necessary to provide DR often presents an opportunity to simultaneously upgrade equipment with energy efficiency measures, improve the operation and scheduling of a load to better serve site needs, and ultimately reduce energy service costs for building owners. These integrated demand-side management (IDSM) measures can lead to a lower effective cost for providing DR service since the installation and purchase of control equipment can be underwritten by a portfolio of benefit streams. We did not undertake a detailed study on the dynamics of site-level electric bill impacts or strategies for IDSM, but included a set of likely possible levels of portfolio benefits to show the implications of comprehensive IDSM measures on DR markets; we incorporated these various benefit streams as *co-benefits* associated with installation of DR enabling technologies.

When we included co-benefits, the effective costs for DR service from batteries and other DR technology options with identifiable parallel value streams was substantially reduced, and made more cost-competitive DR available, as shown in Figure 48. The colors in the lines (top) and bars (bottom) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather and the solid lines are 1-in-10 weather years. The $200 price referent includes a generation (**PURPLE**), transmission (**ORANGE**), and distribution (**GREEN**) component. All of the estimates for supply Shed DR are shifted based on the contributions of TOU/CPP rates, which are shown in **ORANGE** and **GREEN**. Case: Year 2025, Rate Mix #3, mid-AAEE trajectory. For example, including the specified co-benefits resulted in an increase of approximately **3 GW of additional Shed DR** capacity compared with a model run without co-benefits (an increase of roughly 60 percent, mainly from the residential customer sector, where batteries become cost-effective when co-benefits were included).

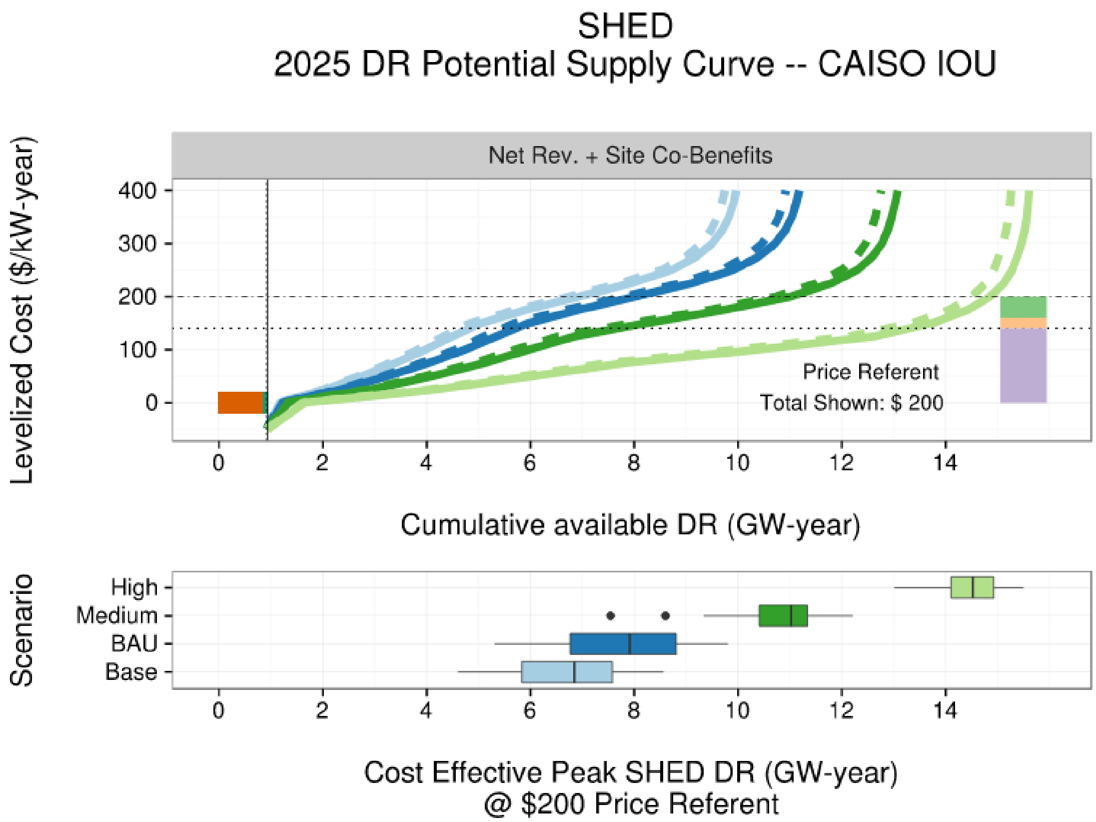

Figure 48: (top) Shed DR potential supply curve results compared to a conventional $200/kW-yr price referent, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

Figure 49 shows estimates of Shed DR potential under the various economic valuation options. Beginning with the upper left quadrant, going clockwise: Supply curves with unadjusted total costs, net total costs with ISO revenue, net revenues with site-level co-benefits, and net revenue with site and distribution system benefits incorporated into Shed supply curves. The unadjusted total costs valuation in the left quadrant presents estimates of approximately 6 GW. As we added revenues and co-benefits to the supply curves, buying down the costs of the DR technologies, we increased the cost competitiveness of the DR resources. In the lower right quadrant, we included net costs (market revenues), site level co-benefits, and distribution system co-benefits, which increase the quantity of cost-competitive Shed DR to ~11 GW at the $200/kW-yr level.

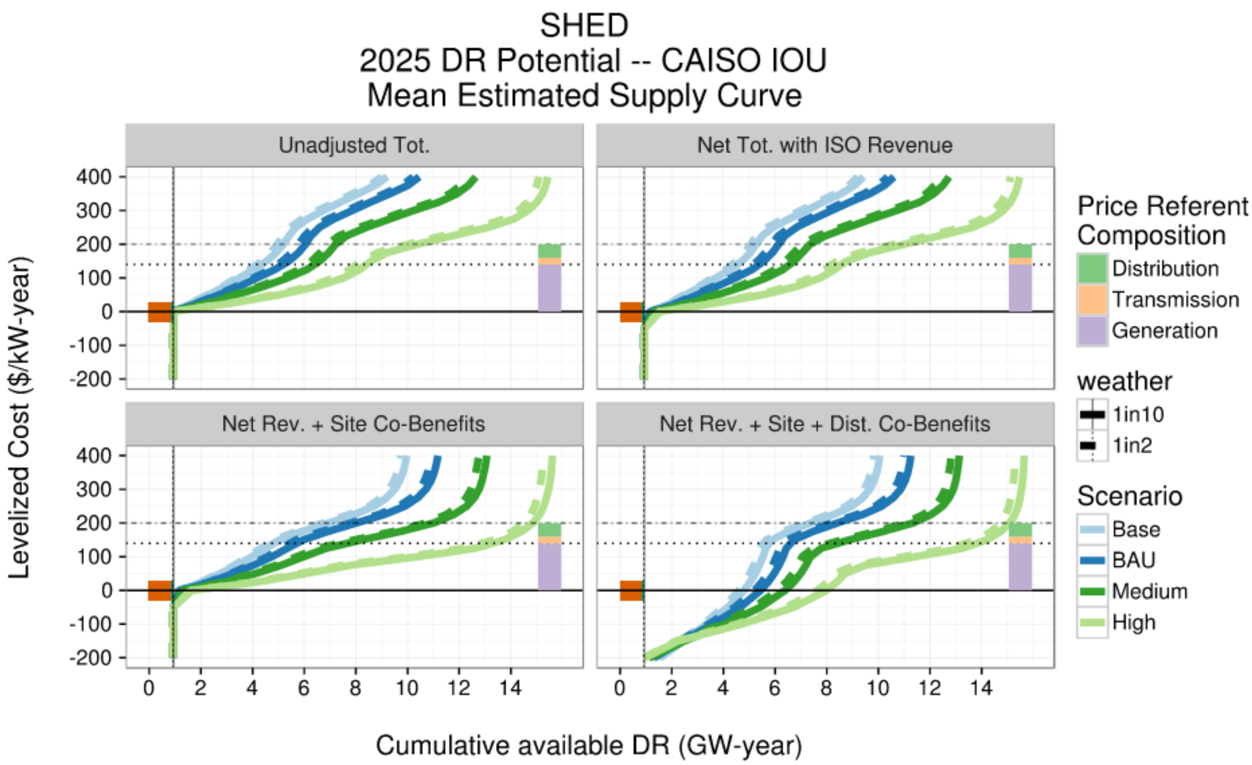

Figure 49: 2025 Shed-type DR potential supply curves with various estimates of revenue streams contributing to the economic efficiency of DR technology costs.

Figure 50 shows the 2025 Shed DR results broken out by utility, sector, and end use. For PG&E, approximately 1,500 MW of the 3,000 MW of Shed potential comes from the industrial sector, while about 800 MW comes from commercial sector, and 600 MW from residential sector. For SCE, Shed potential is driven equally by the commercial and industrial sectors, with approximately 1,250 MW from each sector, and another 400 MW from the residential sector. For SDG&E, commercial sector lighting and HVAC are key end uses that provide the majority of the available Shed DR. Table 13 presents the Shed DR potential in megawatts by sector for each IOU in 2025.

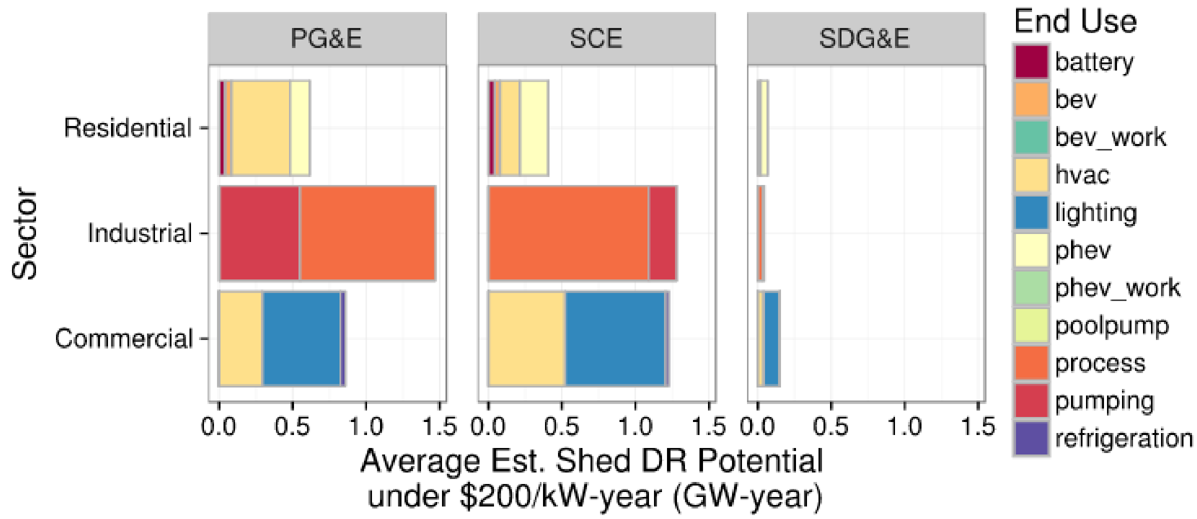

Figure 50: 2025 Shed DR potential by IOU service territory and end-use contributions, under the 1-in-2 weather year, mid-AAEE, Medium scenario with a $200/kW-yr price referent.

These results are particularly helpful for determining what types of DR, based on average costs, provide the greatest contributions to the DR fleet at different price referent levels. This may be helpful for approaching DR program recruitment through targeted marketing. One way to target DR participation that results in high returns on investment could be to identify customers within each sector that have:

- Eligible end-uses with strong coincidence between end-use load baselines and times of system need
- Large potential load reduction, i.e., typically customers with high annual kWh
- Characteristics that show a propensity to participate, such as utility program participation or other demographic factors

Rather than approaching all customers with an offer of DR, a targeted approach to recruiting customers with end-uses that are most cost competitive is efficient. For example, based on our results, targeting Commercial HVAC is in general more cost effective than Residential AC, on an average costs basis. However, the Residential AC end-use is capable of providing more cumulative DR than Commercial HVAC, and the distribution in customer-to-customer cost for DR within the technology are such that it is possible to target a set of very cost-competitive opportunities within the customer base.

Table 13: MW of Shed DR potential by customer sector for each utility, under $200/kW-yr, in 2025.

Sector	Utility	Shed DR Estimated in 2025 under $200/kW (MW)
Industrial	PG&E	1472
Residential	PG&E	616
Commercial	PG&E	859
Industrial	SCE	1281
Residential	SCE	409
Commercial	SCE	1227
Industrial	SDG&E	43
Residential	SDG&E	68
Commercial	SDG&E	151

Figure 50 shows the potential for a given price referent level ($200/kW-year), which is one among many possible appropriate levels depending on the location of shed resources, and our modeling framework leads to estimates across a range of other price levels as well. In Figure 51 below, we show how the end-use technology contributions to Shed vary across price from $0-400 /kW-year. The each sector's contribution is grouped, with boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation. The variety of resources included in the model reflects the emphasis that DR Shed has gotten over the past decades, with a range of application technology that has gone from pilot phase to deployment. For areas where the value of Shed is very high (local capacity areas, and distribution system constrained circuits) there are opportunities that are market ready across several customer classes.

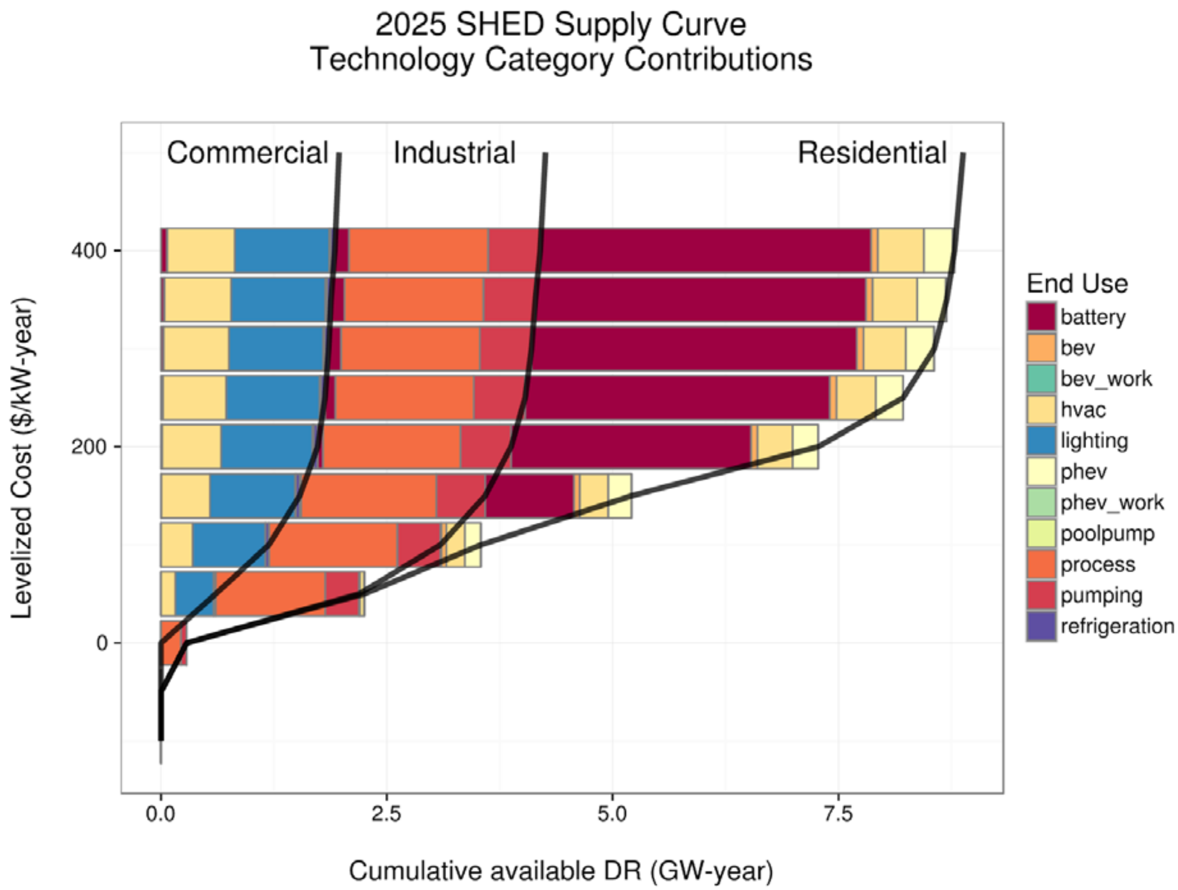

Figure 51: Shed DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

5.4.2. The Importance of Information and Variation in the Model

Recall that we used Monte Carlo simulation to estimate how uncertainty in modeling assumptions for DR technology cost and performance would affect the levelized cost of DR enablement. We simulated variability in modeling assumptions due to both sources of uncertainty by using stochastic sampling to populate the enabling cost, performance, and lifetime of each enabling technology for each cluster. Figure 52 shows supply curves that illustrate the variability in DR technology measure costs. The case here, for illustrative purposes, is a 2025, mid-demand, mid-AAEE, Rate Mix #3, total cost accounting case. (A) Shows all of the stochastic input file runs, (B) shows just the runs for the "deterministic" or static input file (these were the types of runs we conducted in the study's Phase 1), (C) shows the stochastic and deterministic runs together, and (D) shows the deterministic runs in black and

the mean of the stochastic runs (mean quantity x-value for each y-value cost level). The variability of the DR measure has the effect of increasing the estimated Shed potential. The Monte Carlo analysis includes parameters to simulate the effects of uncertainty in the pace of technology development and in site-to-site differences in the actual cost of DR enablement. DR potential increases when market participants can identify and target highest-value sites and enabling technologies.

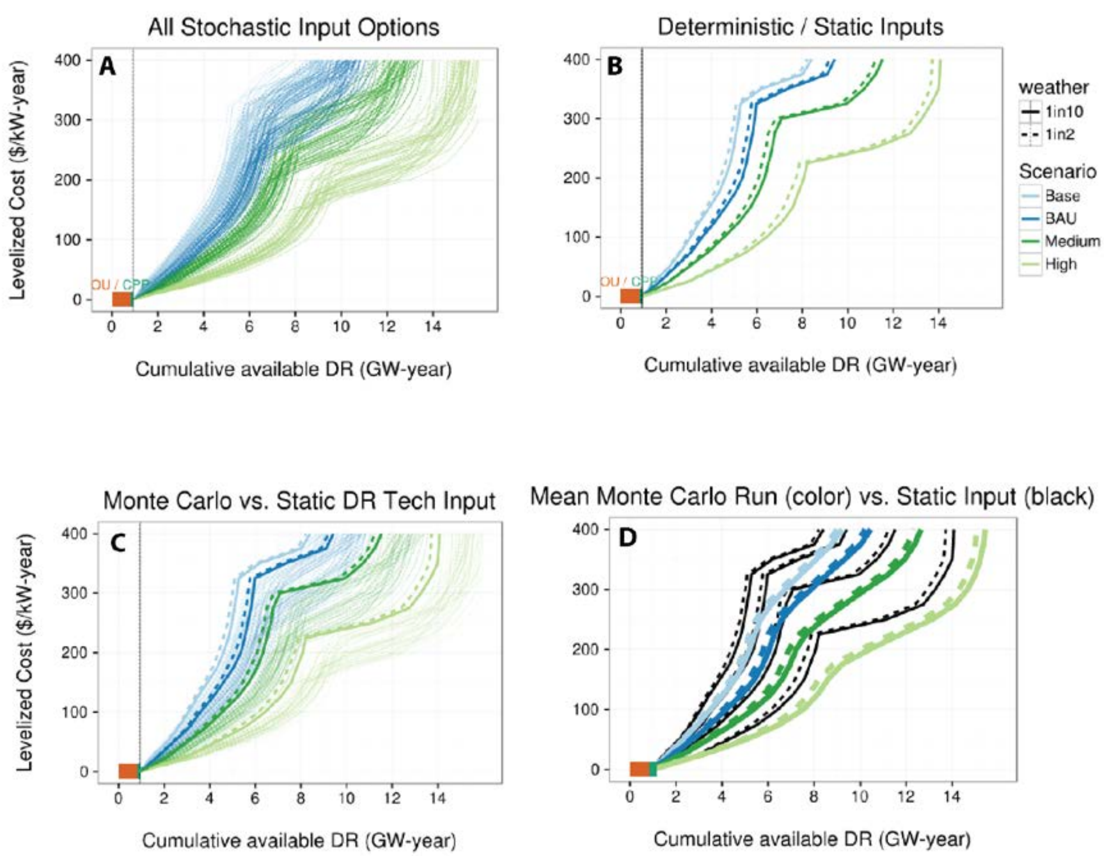

Figure 52: Illustrations of how variation in the technology inputs leads to increased mean potential due to choices available in the market.

5.4.3. Shed DR Value to the Grid

‘Shed’ resources as modeled in this study are those providing the conventional form of downward DR, by which load is reduced to lower peak demands on the grid. California has a long history of implementing DR programs to encourage load reduction. The California Energy Action Plan (EAP) issued in April 2003 placed energy efficiency and demand response as preferred resources and set a goal of meeting 5% of peak loads with demand response by

2007.[23] Building on the avoided cost framework developed for distributed energy resources (DER), E3 supported the CPUC in developing DR cost-effectiveness protocols first adopted in 2010 and updated in 2015.[24] As for DER in general, the protocols include several categories of benefits or avoided costs, including energy, system capacity value, transmission and distribution deferral, GHG emissions, ancillary services, losses and an RPS adder.

By far the largest value for DR in existing DR cost-effectiveness protocols is the generation capacity value. Shed DR has historically provided value by reducing system peak demand. This has been valuable because these highest demand hours generally correspond with the highest variable cost of electricity. A reduction in peak demand allows deferral of investment in peaking capacity, resulting in cost savings to ratepayers.

Transmission and distribution deferral has been the second largest value, though the vast majority of DR has been called based on system rather than local distribution conditions. The DR cost-effectiveness protocols include several adjustment actors to properly evaluate the capacity value of the DR resource to the traditional supply side resource of a combustion turbine (CT). The adjustment factors are designed to account for limitations on DR as a resource, including advanced notification requirements and the maximum frequency and duration of calls permitted.

The capacity value of DR is calculated based on the estimated cost of procuring capacity resources to meet Resource Adequacy (RA) requirements. RESOLVE incorporates this convention through its annual peak capacity requirement. RESOLVE adds new capacity resources as needed, and demand-side resources provide value by deferring the need for this new capacity. When there is generation capacity significantly in excess of peak load, RESOLVE attributes a low system capacity value for Shed DR.

RESOLVE shows relatively low value for Shed DR in the 2020 – 2030 timeframe: \$0.72-1.32/kW-yr. for the first kW-yr. of Shed resource added to the grid in 2020, \$3.80-4.10/kW-yr. in 2025, and \$4.76-4.94/kW-yr. in 2030. See Figure 53. The value per kW also decreases as more Shed resources are added to the grid: in 2025, the 10,000th MW of Shed resource added to the grid is valued at approximately \$2.50/kW-year (See Figure 54). The value that the Shed resource provides stems largely from reductions in fuel costs due to reduced load, as well as the value that flexible capacity resources have in in alleviating ramping and capacity constraints to reduce integration costs and curtailment of renewable generation.

[23] The document "California Demand Response: A Vision for the Future (2002-2007)" is included in D.03-06-032 as Attachment A. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/26965.ht

[24] See CPUC Decision D 10-12-024, Rulemaking R 13-09-011 and Decision D. 15-11-042

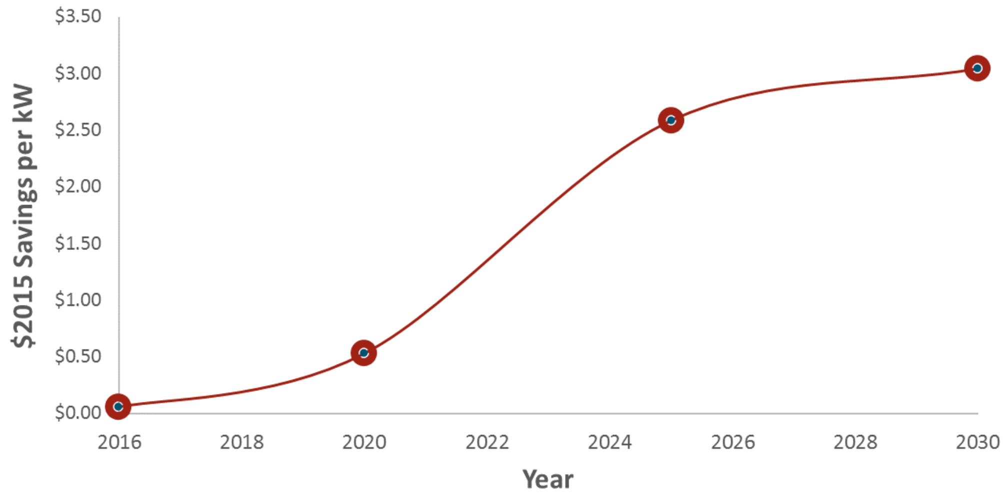

Figure 53: Value of first kW-year of Shed over time, High Curtailment Future, Mid AAEE scenario

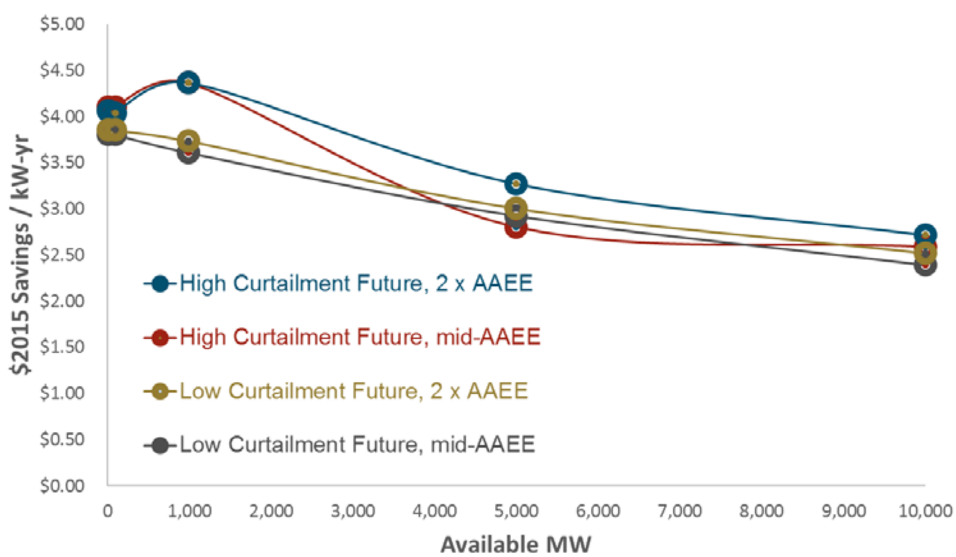

Figure 54: Marginal savings per added MW of Shed Resource, 2025

RESOLVE finds that Shed DR does not avoid significant operating or investment costs for utilities and their ratepayers. This is due largely to the fact that RESOLVE does not need to add any new system generation capacity at any point during the modeling period because of the capacity surplus assumed in the CPUC's 2016 LTPP scenarios. The LTPP scenarios reveal a sizeable excess supply in the 2017 – 2030 timeframe. Figure 55 below shows this 'Net System Balance' from the CPUC's 2016 LTPP Scenario Tool: the surplus of forecasted supply

resources (for this analysis we excluded DR) above forecasted demand in August of each year.[25] This positive net system balance significantly reduces the value of Shed DR, since there are no capacity additions that can be deferred over the modeling time horizon.

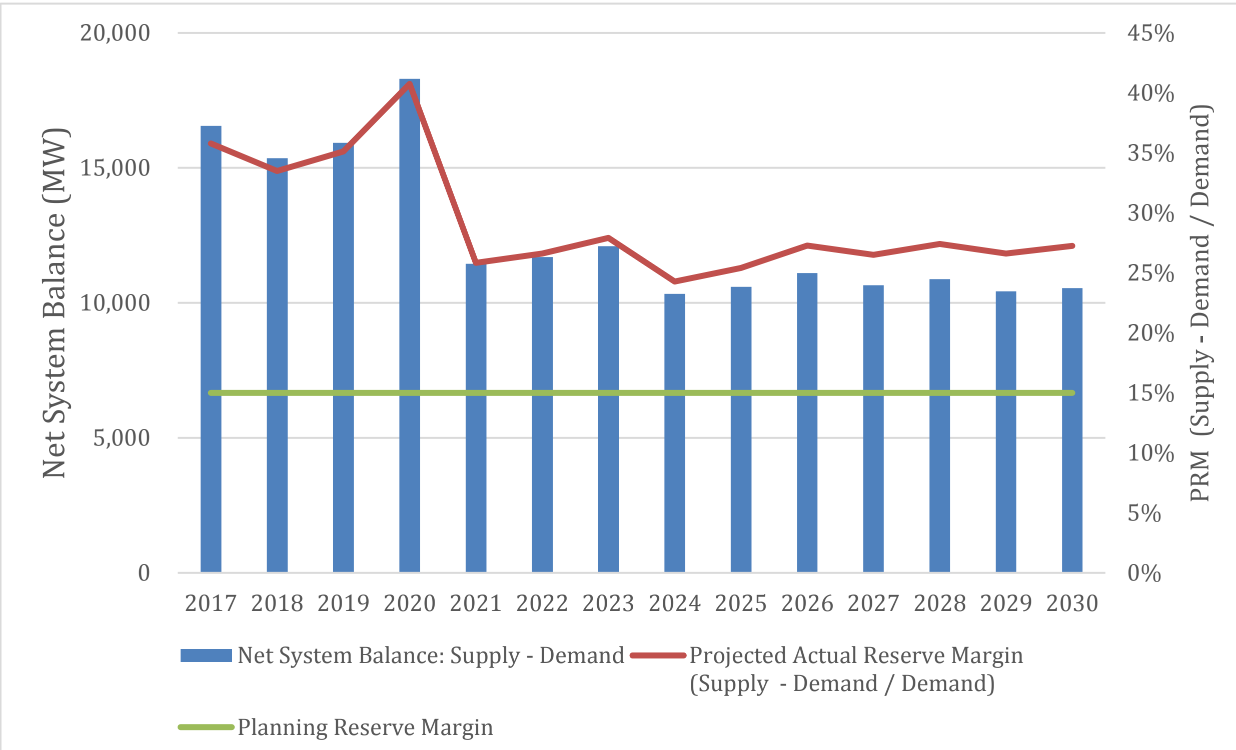

Figure 55: Net System Balance, CPUC 2016 LTPP Scenario Tool, 2017 - 2030[26]

To understand the dynamics underlying the changes in Shed value over time (recall Figure 53),

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[25] CPUC Energy Division 2016 LTPP Scenario Tool for R.16-02-007, August 2016, http://www.cpuc.ca.gov/General.aspx?id=11681 . August is the usual month of system peak capacity needs – see Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for Use in the California Independent System Operator's 2016 – 17 Transmission Planning Process and Future Commission Proceedings, May 17, 2016, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673.

[26] Net System Balance (forecasted supply – forecasted demand) from the CPUC's 2016 LTPP Scenario Tool. This scenario assumes a mid (1-in-2) IEPR net load forecast, the California Energy Commission's 'SB 350 additional achievable energy efficiency' forecast, counts existing supply from CPUC's Net Qualifying Capacity list, assumes additional generating resources based on a screened list of CEC siting cases, and excludes behind-the-meter generating resources from the supply calculation. We have also excluded Dispatchable Demand Response from the analysis. Source: CPUC Energy Division 2016 LTPP Scenario Tool for R.13-12-010, February 2015, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6636

it is useful to look at changes in system dispatch on a high Shed day over time. Recall that RESOLVE models 37 day types (see Appendix H-2.2 for further detail on day type methodology). The following figures show system dispatch resulting from the RESOLVE model on day type 29, which is a high net load day in August and displays the highest Shed dispatch of any day type in 2030. The scenario modeled in these figures is the High Curtailment Future, Mid-AAEE scenario, with 10,000 MW of Shed resource added to the system. This corresponds to the farthest right, red data point in Figure 54.

In interpreting these figures, recall that RESOLVE models each generating resource with an associated operational cost and availability, *with the exception of Shed*. Shed is modeled at zero cost, and in the case shown here is modeled as 10,000 MW of Shed resource available in any hour, up to a 200,000 MWh annual cap. Note that there are no limits on the number of Shed calls, only on the total annual MWh. The *amount* of Shed made available to the system is thus exogenous to RESOLVE, but the *dispatch* decisions over the days and years are made by RESOLVE to create maximum value to the CAISO system over the 2016 – 2030 period. This value comes in the form of reduced investment and operational costs (see Appendix H for further detail on RESOLVE optimization logic and DR modeling). The scenario shown here includes the California Storage Mandate, plus any additional storage that RESOLVE finds cost-effective to dispatch.

The California storage mandate[27] calls for 1,325 MW of storage to be installed by California's IOUs by 2025. This mandate is included in all RESOLVE scenarios as a block of four-hour duration batteries, and is treated as exogenous to all DR modeling. That is, none of the resources installed as part of the Storage Mandate are assumed to be available as Shift or Shimmy DR resource, and none of the benefits from this storage are included in our Shift and Shimmy results.[28]

Figure 56 shows dispatch on day type 29 in 2016, and displays conventional use of Shed DR to minimize peak net load. Storage is dispatched in the same way.

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[27] For more information on AB 2514 regarding energy storage systems, see

http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200920100AB2514

[28] E3 conducted a sensitivity analysis in RESOLVE to evaluate the impact of the Storage Mandate on Shift DR services and estimate the change in system level value for Shift. **Appendix H-5** presents the findings of this Storage Mandate sensitivity analysis.

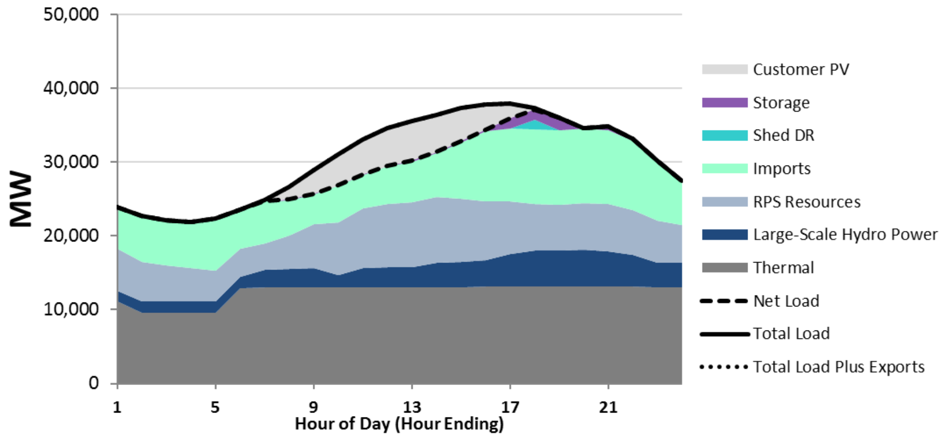

Figure 56: System dispatch on RESOLVE Day Type 29 (high net load day in August), 2016. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

In 2020, we observe more RPS resources and customer-sited PV on the system – see Figure 57. Just as in 2016, we see the Shed DR resources called to reduce the system's peak net load.

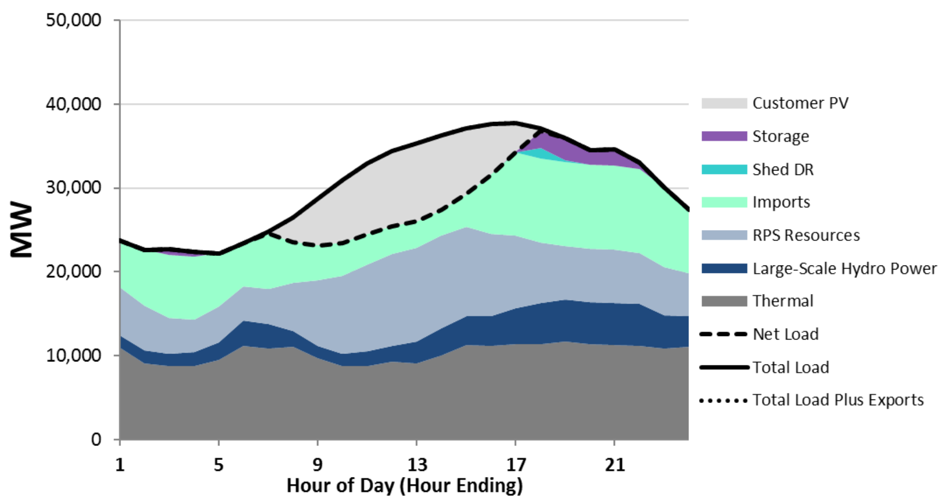

Figure 57: System dispatch on RESOLVE Day Type 29 (high net load day in August), 2020. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

In 2025, we model significant renewable capacity contributing to the system's supply. At this point, RESOLVE starts to see slightly more economic opportunities for the utilization of conventional DR: meeting ramping needs. As customer-sited solar becomes a larger contributor to mid-day electricity supply, other generators must be ramped down to prevent curtailment. However, the sun goes down as the evening demand peak sets in, creating a need to rapidly ramp-up non-solar generators back to meet evening load. In the absence of DR, this need is met in the RESOLVE cases by a combination of increased California gas dispatch, higher imports,

and energy storage discharge. When Shed DR is available, it is frequently dispatched by RESOLVE during these steep evening ramps. However, the low value for Shed resources even in 2025 and 2030 (recall Figure 53) suggests that RESOLVE does not find significant value for Shed resources in reducing renewable curtailment due to alleviating upward ramping constraints in the 2016 – 2030 timeframe. Rather, the value that Shed DR provides in dispatch is related to fuel savings from reduced conventional dispatch (this includes CAISO CCGT's, peaker plants, gas turbines, ICEs). This value is relatively small, even during the peak periods. As discussed in prior sections, significantly more value is created by DR resources that can move load into the middle of high renewable curtailment days to reduce curtailment.

It is worth noting that RESOLVE's hour alignment is in standard time, meaning that the net load peak displayed in the corresponding dispatch charts as hour-ending 18 is actually occurring at hour-ending 19.[29] This means, quite simply, the sun is setting by the time this peak occurs. In other words, regardless of how much solar is added, the net load peak can only be pushed so far back. With this in mind, we do not see a significant shift of the net load peak to later in the evening.

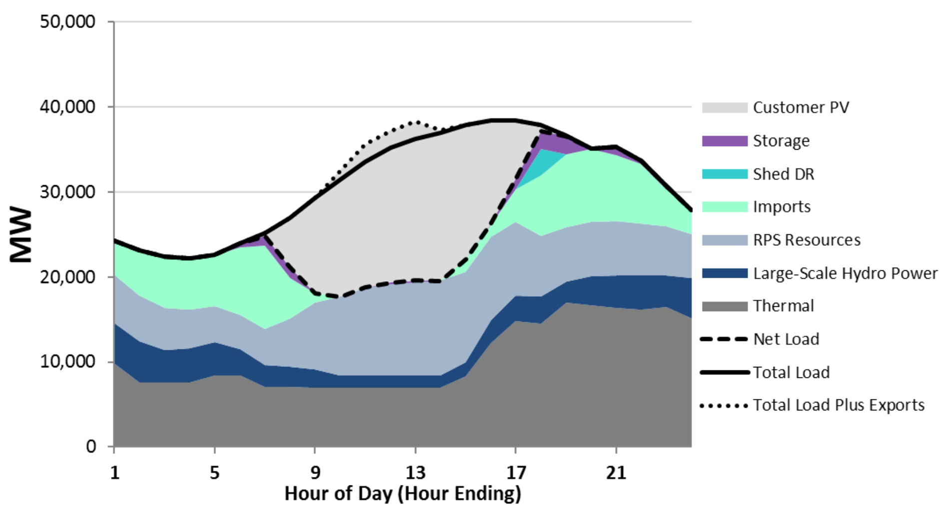

Figure 58: System dispatch on RESOLVE Day Type 29 (high net load day in August), 2025. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

The story in 2030 is similar to that of 2025, only further exacerbated. On this high net load day in 2030, we observe a very small amount of renewable curtailment. This is an outcome of the system's inability to meet a steep ramping constraint, as non-renewable generators must be kept on-line to meet the evening uptick in demand. On this day, we see that Shed DR is dispatched

[29] This is true for all of RESOLVE's dispatching. That is, any figure featuring a 24-hour timeframe on the X-axis is in standard time.

during the steepest ramping hours to try and minimize this challenge to grid operations. It is worth noting here that, because Shed DR is a free resource (that is, RESOLVE sees no operational cost of dispatching Shed DR), dispatching it simply reduces energy demand. This reduces operational costs. With this in mind, RESOLVE will always dispatch Shed DR up to whatever its annual dispatch budget is. If the annual energy budget of Shed DR were increased, RESOLVE would continue to all of it up. More specifically, because the variable cost of serving energy is highest when demand is highest, RESOLVE will dispatch its Shed DR budget to reduce the observed net load peak.

The sequence of dispatch figures reveals an increase in the magnitude of the conventional DR being dispatched on this individual day over time. Here, it is important to note that the above dispatch represents only one of the 37 day types included in RESOLVE (see Appendix H for further description of the day type methodology). In 2016 and 2020, RESOLVE chooses to dispatch a maximum of 1,279 and 1,274 MW of Shed, respectively, on each day of this type, and spreads the remaining Shed availability across other day types. In 2025 and 2030, as the variable (renewable) generation on the grid increases, we see more variance across days in system-level dispatch. In other words, the 37 day types in RESOLVE look *more similar* in the earlier years of our RESOLVE modeling, but take on more variance in later years. Because of this, RESOLVE optimizes for lowest grid costs by dispatching a more significant quantity of Shed DR in later years (a maximum of 3,051 MW in hour 18 in 2025, 3,206 MW in hour 18 in 2030) during this particular high net load day. That is, as the supply and demand profiles (net load, supply mix, renewable generation, etc.) of day types become more varied over time, the potential value of a MW of Shed DR changes drastically. A high net load day, which features steep ramping needs and a high net load peak, as displayed in the above Figures, creates a much more valuable Shed DR dispatching opportunity than a low net load day, which would have both more moderate ramping and peak demands. We see this consolidation of Shed DR dispatching into fewer days and at more extreme levels in Figure 60.

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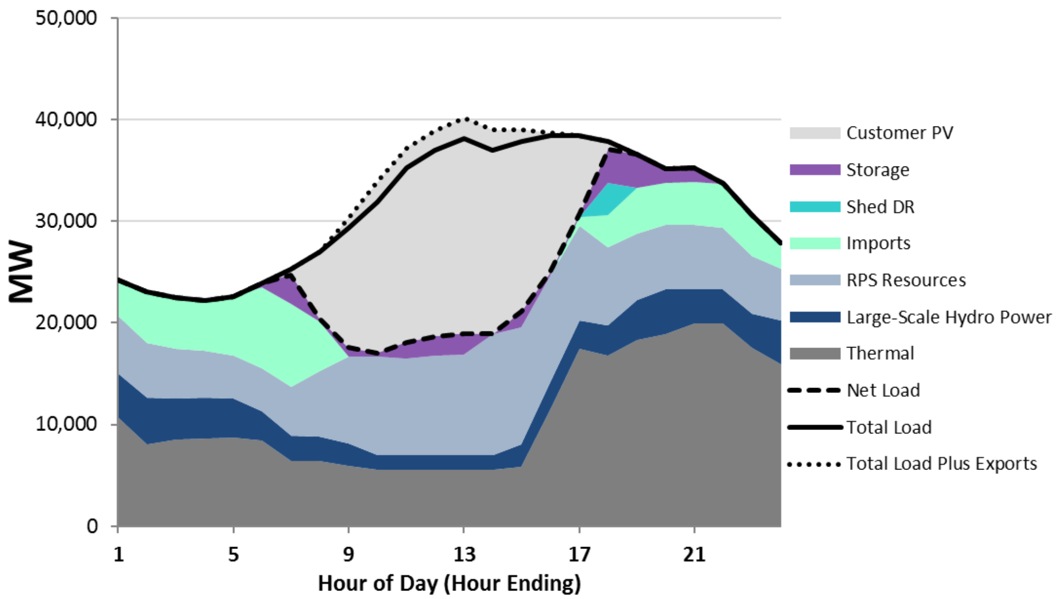

Figure 59 System dispatch on RESOLVE Day Type 29 (high net load day in August), 2030. High Curtailment, Mid AAEE scenario, with 10,000 MW of hourly Shed resource availability (max. 200,000 MWh per year) modeled at zero cost.

Figure 60 shows the total MW of Shed DR dispatched for each day type in RESOLVE in each year (2016, 2020, 2025, 2030). Arrows indicate the direction of significant movements in Shed dispatch over from 2016 to 2030. Note that each day type has been weighted by its associated weight to show the full Shed dispatch for the day type across the relevant year. 2016 and 2020 display relatively flat Shed DR dispatch across the 37 day types. For 2025 and 2030, however, most of the Shed DR dispatch is found during fewer day types. Days 17 and 29, in particular, show large uptakes in shed dispatching as time goes on.

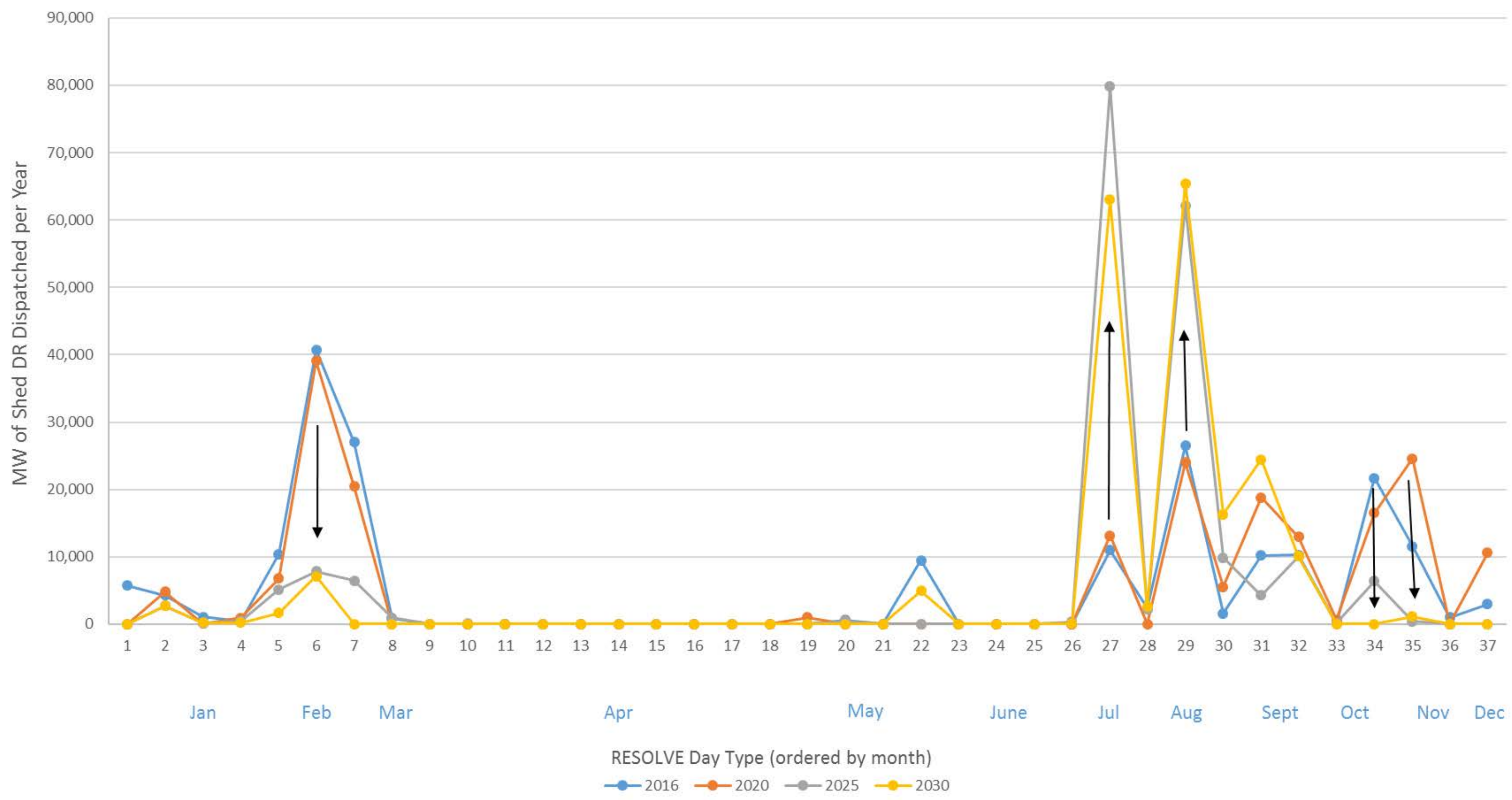

Figure 60: Annual Shed DR dispatched during each RESOLVE Day Type. High Curtailment, Mid AAEE scenario, with 10,000MW of hourly Shed resource availability (max. 200,000 MWh per year)

It should be noted that Shed DR may have additional value beyond that modeled in RESOLVE. RESOLVE captures the value of Shed in providing System Capacity, but does not capture any additional value of DR that is located in specific areas. For example, DR resources in certain areas such as the Los Angeles Basin may have Local Capacity Reliability (LCR) value by providing a capacity resource in a transmission-constrained area. Shed DR in some locations may also have value in deferring transmission and distribution system investments that are not captured in RESOLVE. In addition, RESOLVE does not capture a reduction in the need of Load-Serving Entities to procure RA capacity from existing resources.

5.4.4. Valuing Shed Service Type DR with Supply Curves and Levelized Demand Curves

As noted previously, our analysis included two economic valuation methodologies. The second methodology, that of using RESOLVE to generate system *demand* curves, resulted in drastically different conclusions as to what the economically cost-effective amount of Shed DR is. Figure 61 shows the Shed supply curve for 2025 and includes the system levelized value approach under the high-curtailment case. The green and blue colors in the lines (top) and bars (bottom) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather and the solid lines are 1-in-10 weather years. The Low-Curtailment case (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines represent the levelized demand curves. The equilibrium price is at the intersection of the levelized demand curves and the supply curves. All supply Shed DR estimates are shifted based on the contributions of TOU/CPP rates, which are shown in **ORANGE** and **GREEN**. (Case: Year 2025, Rate Mix #3, mid-AAEE trajectory.) When examining Shed DR resource value under the RESOLVE levelized demand curve, we found that Shed-type resources are not cost-competitive; that is, there was no value for Shed resources in either 2020 or 2025, because there was no shortage of generation capacity.

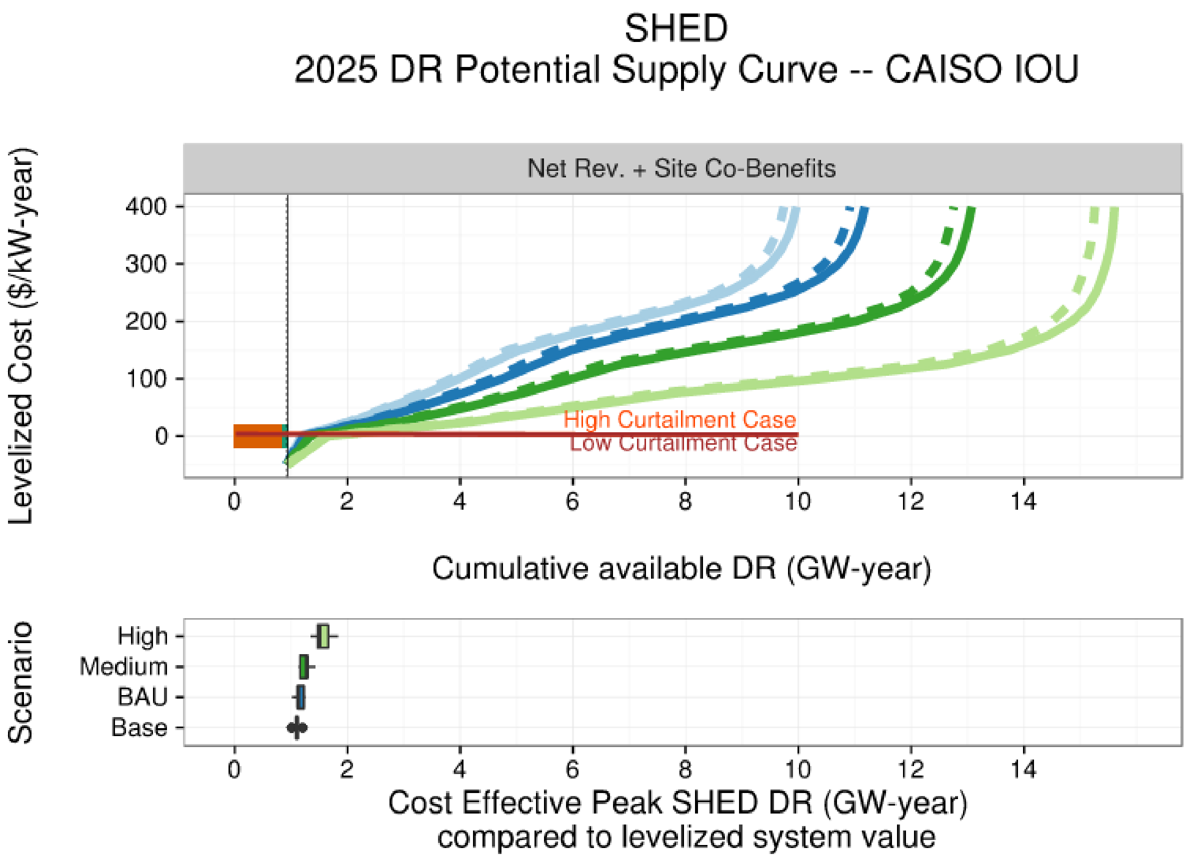

Figure 61: (top) Shed DR potential supply curve results compared to the levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

The levelized demand curve potential (Figure 62) indicates cost-competitive Shed resource DR to be about 0 MW. In other words, the value of Shed-type resources is virtually zero because there are no constraints on capacity type resources over the next 15 years. We note that if one considers revenue that should be available in peak hours of the market, there is some economically viable Shed resource (on the order of 500 MW in 2025).

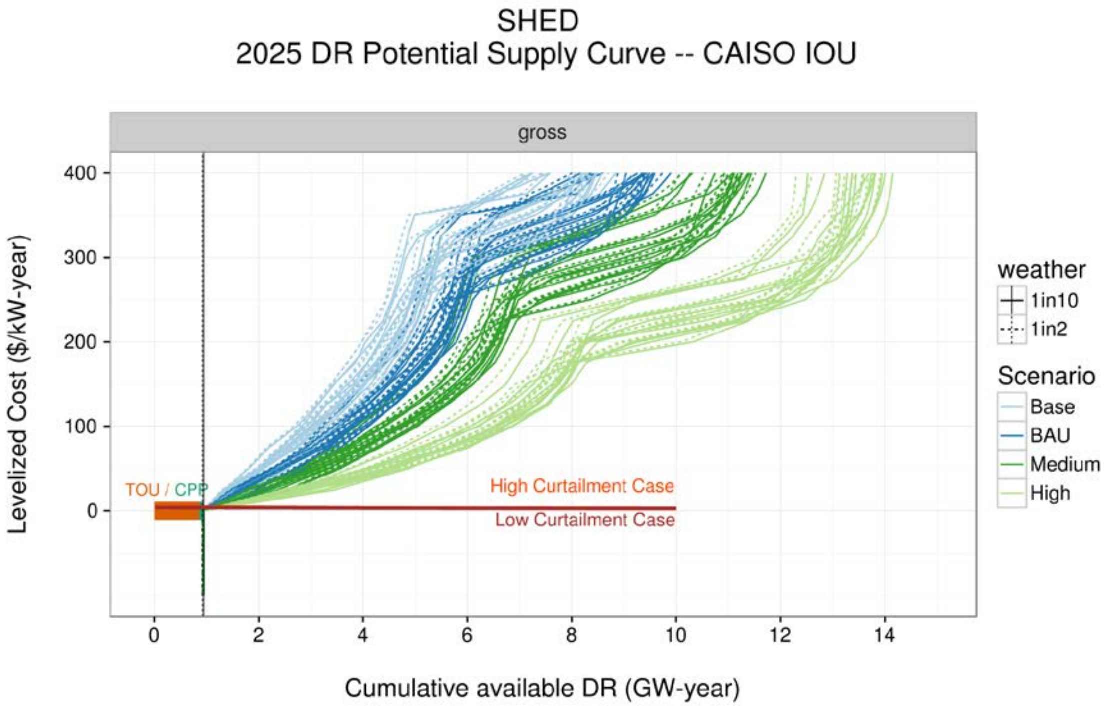

Figure 62: Combined supply-demand curves for Shed DR in 2025. The levelized demand curve shows Shed DR with approximately zero value, leading to approximately no cost-competitive Shed DR.

Below, in Figure 63, we incorporate the first-order distribution system level benefits into the economic valuation of the DR potential supply curves. Beginning with the upper left quadrant, going clockwise: the Supply curves providing the Shed service type DR to the grid are represented with unadjusted total costs, net total costs with ISO revenue, net revenues with site-level co-benefits, and net revenue with site and distribution system benefits incorporated into Shed supply curves. Each quadrant depicts the estimates developed for the Base, BAU, Medium and High scenarios using Monte Carlo analysis to estimate the range of uncertainty. In the lower right quadrant, we include potential revenue streams from serving the distribution system and avoiding investment in infrastructure upgrades; these results are discussed in detail below.

In Figure 64**,** box plots depict the 2025 Shed-type DR potential as compared to the system-level value from the levelized demand curves. Each quadrant includes estimates of revenue streams contributing to the economic efficiency of DR technology costs. Beginning with the upper left quadrant, going clockwise: the unadjusted total costs, it shows the net total costs with ISO revenue, net revenues with site-level co-benefits, and net revenue with site and distribution system benefits. Each quadrant depicts the range of DR potential estimates developed for the Base, BAU, Medium and High scenarios and the range of values from a Monte Carlo analysis that examined the range of uncertainty in DR enabling technologies' costs and performance.

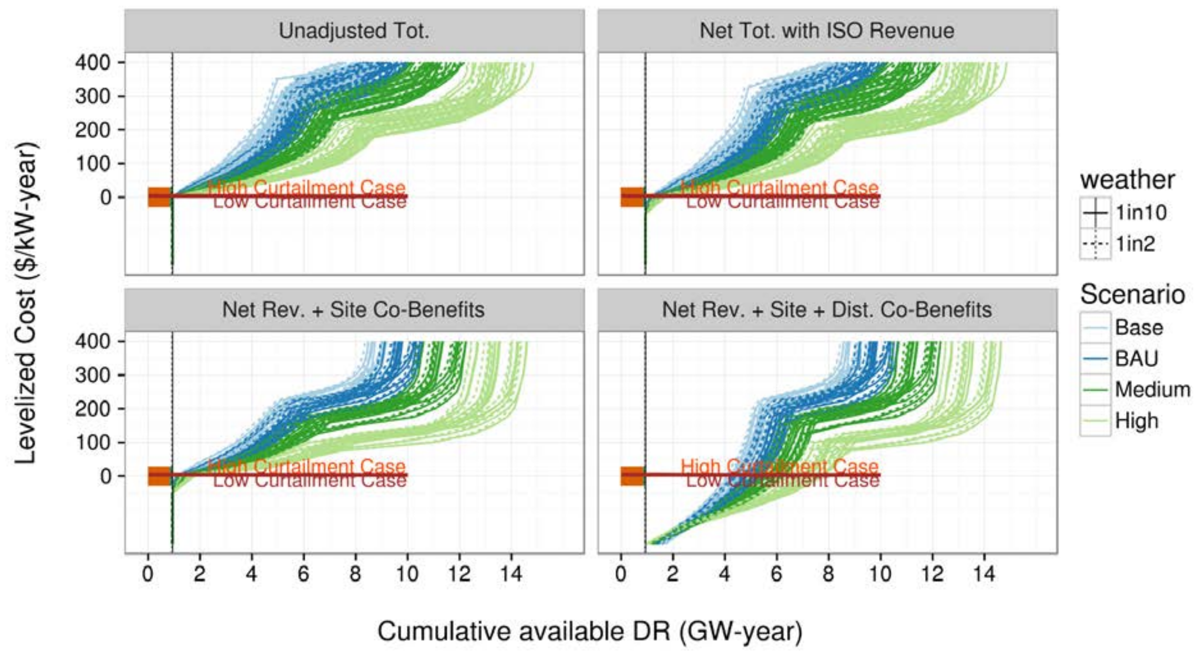

Figure 63: 2025 Shed-type DR potential supply curves as compared to the system level value supply curveswith various estimates of revenue streams contributing to the economic efficiency of DR technology costs.

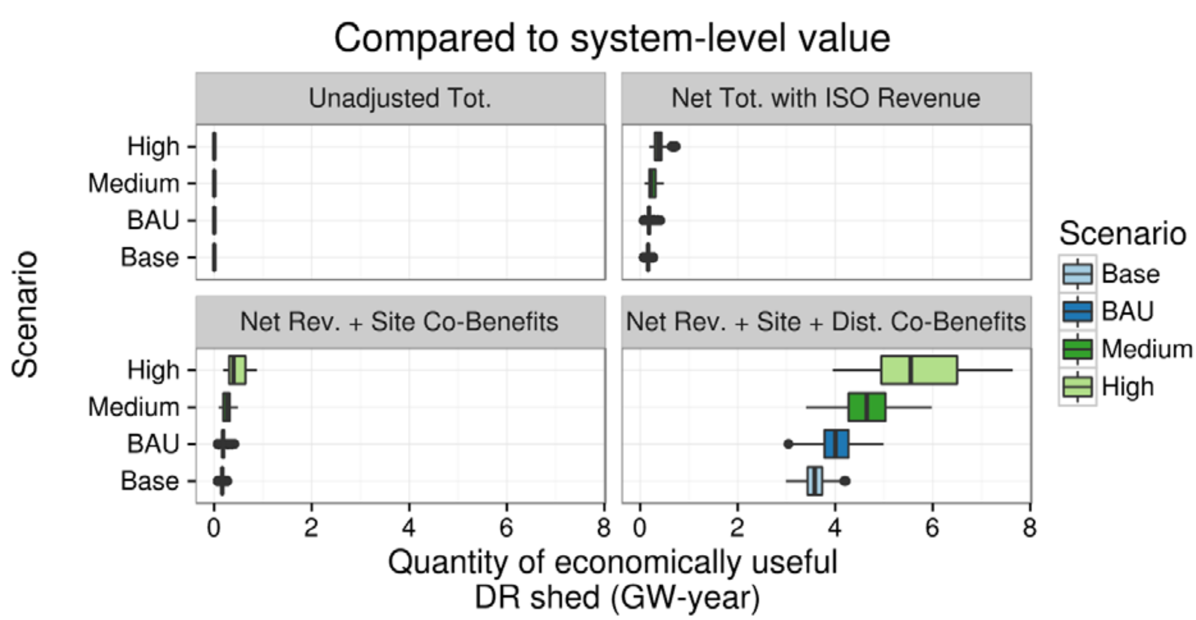

Figure 64: Box plots depicting the 2025 Shed-type DR potential as compared to the system-level value from the levelized demand curves.

Table 14 and Table 15 present the cost competitive prices and quantity for Shed DR from the DR Futures supply curves and the RESOLVE levelized demand curves under the medium

scenario, and represent the price at the intersection of each curve. The price and quantity reflects the levelized cost and value to the grid; in other words, the price for each DR unit (MW or MWh) is economical when compared to the costs of other generation resources. The costs and quantities are segmented by percentiles that capture the variance around the intersection of the demand and supply curves for each service type. Note that Shed has no value to the grid under the "Total" cost framework, and only provides value once benefits streams are incorporated, such as site level co-benefits and distribution system benefits.

Table 14: Levelized Price and Quantity of Cost Competitive Shed DR by Percentile (Low Curtailment Scenario)

Shed DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Site Co-Benefits	Net Revenue + Site + Distribution System
25th Percentile Price per kW ($)	$0	$0	$0	$0
25th Percentile Quantity (MW)	-	246	246	4,920
50th Percentile Price per kW ($)	$0	$0	$0	$0
50th Percentile Quantity (MW)	-	360	360	5,082
Mean Price per kW ($)	$0	$0	$0	$0
Mean Quantity (MW)	-	335	339	5,112
75th Percentile Price per kW ($)	$0	$0	$0	$0
75th Percentile Quantity (MW)	-	369	372	5,250

Table 15: Levelized Price and Quantity of Cost Competitive Shed DR by Percentile (High Curtailment Scenario)

Shed DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Site Co-Benefits	Net Revenue + Site + Distribution System
25th Percentile Price per kW ($)	$0	$0	$0	$0
25th Percentile Quantity (MW)	-	242	242	4,920
50th Percentile Price per kW ($)	$0	$0	$0	$0
50th Percentile Quantity (MW)	-	360	360	5,082
Mean Price per kW ($)	$0	$0	$0	$0
Mean Quantity (MW)	-	331	331	5,112
75th Percentile Price per kW ($)	$0	$0	$0	$0
75th Percentile Quantity (MW)	-	369	369	5,250

Table 16 below summarizes the expected Shift DR potential by utility, by year. It shows the breakdown of expected potential by utility service area, and the implications of the portfolio benefits of multiple value streams (through cost accounting framework modifications). The core value from widely distributed Shed resources derives from serving the distribution system, discussed in Appendix I. Under the assumptions we used to estimate potential for distribution system support, we identified up to 4–5 GW of Shed DR that is cost-effective (which is illustrated by the Cost Frameworks in the table). Since distribution system operations are managed below the ISO level by individual utilities and load-serving entities, Shed DR servicing the distribution system falls into the load-modifying DR classification.

Table 16: Shed potential (MW-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

	2020			2025		
Cost Framework	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Unadjusted Tot.	0	0	0	0	0	0
Net Tot. with ISO Revenue	110	210	2	130	250	2
Net Rev. + Site Co-Benefits	110	210	2	130	250	2
Net Rev. + Site + Dist. Co-Benefits	2100	2200	150	2500	2500	210

5.4.5. Shed Service Type DR Potential: Local Capacity Areas

Although Shed-type DR is expected to provide little value to bulk power system operation and investment planning, we found that there can be significant value in geographically targeted Sheds for certain areas, as illustrated in Figure ***65***. These supply curves show how DR could meet the needs of capacity constrained areas. The figure shows a subset of the system-wide Shed resource: only fast-responding (20 minute dispatch) resources that are located in current-day capacity constrained areas (Los Angeles Basin, Big Creek/Ventura, and San Diego), where many of the needs must be met with local generation. Significant DR resources are located in these areas of California where local capacity constraints create need for local DR. If the value of Shed in these constrained "local capacity areas" (LCAs) is equal to $200 per kW-year (an alternative technology price referent), we found that by 2025 there could be approximately 2–6 GW of local, cost-effective Shed DR. Table 17 shows a range of potential for "local" DR, with the system-wide potential for fast DR and the current local capacity area totals indicated.

Many DR technologies are able to respond within a 20-minute dispatch window. Those that are unable to respond within this timeframe, based on our estimation, include "manual" response in the residential sector (i.e., those responses where homeowners must take action) and some industrial processes that cannot be interrupted without longer notice.

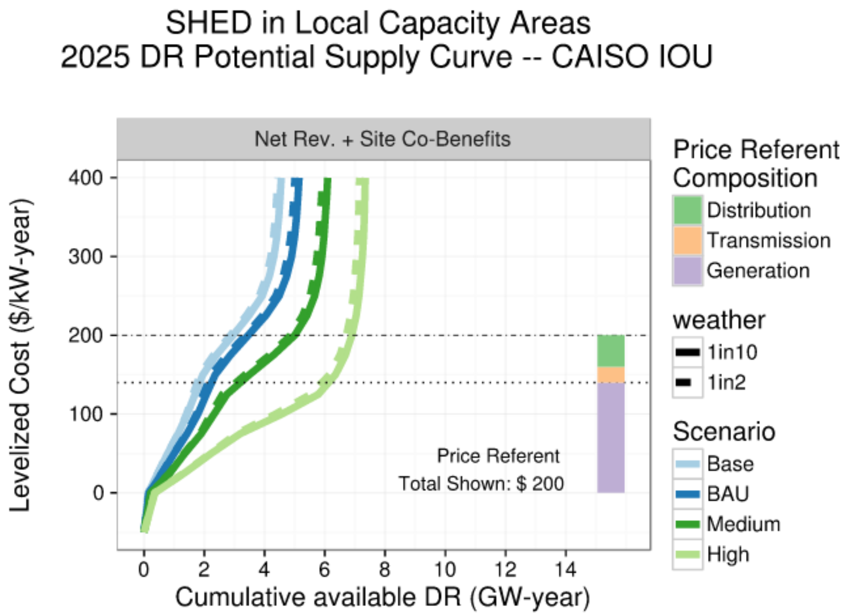

***Figure** 65: Supply curve for DR Shed available in significant local capacity-constrained areas (Los Angeles Basin, Ventura/Big Creek, and San Diego).*

Table 17: Local shed potential (MW-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, a $200/kW-year price referent, and Rate Mix #3. The results for the whole service territory are given along with the current local capacity constrained areas (LCA) results (in parentheses) for: LA Basin, Big Creek/Ventura and San Diego.

	2020			2025		
Cost Framework	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
Unadjusted Total	2300 (0)	2400 (2100)	170 (170)	2900 (0)	2900 (2500)	260 (260)
Net Total with ISO Revenue	2400 (0)	2400 (2100)	180 (180)	3000 (0)	3000 (2600)	280 (280)
Net Revenue + Site Co-Benefits	2900 (0)	3100 (2700)	320 (320)	4300 (0)	4600 (4100)	660 (660)
Net Revenue + Site + Dist. Co-Benefits	3000 (0)	3200 (2800)	330 (330)	4400 (0)	4700 (4100)	670 (670)

5.4.6. Emergency and Contingency DR

In this study, we do not explicitly model Contingency Reserves and Emergency DR, but both could create value and revenue opportunities from appropriately designed Shed DR.

Contingency reserves are maintained to support system reliability in transmission-scale loss events. These "Spinning" and "Non-spinning" reserves are currently procured in operational capacity markets. It is plausible fast Shed DR could participate in these markets in the future with appropriate telemetry and rules, but this may not be a significant driver for additional DR potential since there are modest market clearing prices ($0.50-$7.00/MW were the average prices in the 2015 CAISO market[30]) and relatively low quantities needed (800 MW each for spin and non-spin). Future work could seek to better-understand the future value of contingency reserves as a DR strategy.

Emergency DR are resources that only are dispatched in extreme events when contingency resources are not sufficient to prevent blackouts and maintain system reliability. Emergency DR can add value by avoiding or limiting the extent of a blackout. Future work is needed to quantify the value of this type of service, as there is not sufficient evidence available to the study team to make an estimate of how likely it is that an emergency DR event will successfully prevent a blackout, particularly because every blackout has unique characteristics and causes.

Broadly speaking, blackouts are caused by a range of factors but the most typical proximate causes for those at the system level are widespread natural disasters or contingency events that lead to cascading failures in the transmission system. We would not expect DR to be able to mitigate blackouts caused by natural disasters but it is plausible that DR could enhance the capabilities of system operators to prevent or contain cascading failures. Future work is required to estimate the likelihood of DR both being available for dispatch and avoiding blackout.

If DR were able to avoid blackouts, the value to society is uncertain, but potentially large. Estimates of the value of lost load range from $0-$35,000/MWh, depending on the types of loads and services that are affected, and are highly variable depending on the circumstances for the customer[31]. There are wide-ranging estimates for the economic losses from large blackouts, up to billions of dollars in aggregate annually on the national level[32]. Future work to better understand both the value of avoiding blackout and the potential role for DR in mitigating

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[30] https://caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

[31] *Estimating the Value of Lost Load* by London Economics for ERCOT (2013)

[32] *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers* (2004) K. LaCommare and J. Eto LBNL-55718 and

cascading failure is needed.

5.4.7. Shed Service Type Pathways

Our research suggests that a large potential resource of Shed DR exists in 2025, ranging from between 2 and 10 GW depending on the technology costs and performance scenario. However, as system capacity is overbuilt in pursuit of achieving the 50 percent RPS, there is little need for system-level peak-shed DR through 2025. Rather, the value of Shed DR is derived from servicing local capacity and distribution system needs.

"Our research suggests that the focus on system-level Shed (peak load capacity resources) should be redirected to focus on local and distribution-system needs, and that the control technology and business relationships in place could be the foundation of new portfolios that combine targeted and/or fast Shed with Shift."

Based on an expected future generation fleet consistent with long-term procurement planning and reasonable facility retirement schedules, the RESOLVE model found Shed to have a very low system-level value compared to price referent values that are often cited. For example, 10,000 MW of available Shed resource saves the CAISO system only $31 million in 2025, or about $4 per kW-year. In our system levelized value analysis, we examined the equilibrium price at the intersection of the supply and demand curves for the DR service types. Results from that analysis suggest that there is 100–400 MW of cost-competitive Shed DR resources in 2025 that can compete based on energy market participation.

For the vast majority of the Shed DR resources, the costs of enablement exceeded the value they provided to the grid. However, about half of the Shed DR resources in California are in one of three LCAs where a higher price referent may be called for, based on local capacity and distribution system needs. When we accounted for opportunities to service these local system needs, we observed 1–4 GW of Shed DR that is cost-effective for avoiding or deferring feeder and substation-level upgrades that would otherwise be required.

These findings challenge the conventional wisdom of peak capacity DR programs in California. For years, the greatest need to the electricity grid was to manage peak demand; however, with the mass implementation of renewable generation and mandates to meet even higher RPS standards of 50 percent, the challenges of the grid have shifted away from peak capacity shortfalls, thus drastically reducing the need for Shed-type resources for serving the CAISO balancing authority over the coming decade and beyond. This suggests that the focus on system Sheds should be redirected to focus on local and distribution-system needs, and that the control technology and business relationships in place could be the foundation of new portfolios that

combine targeted Shed and/or Shift.

5.5. Ancillary Services with *Shimmy*

Fast DR that operates on seconds-to-minutes ("regulation") and minutes-to-hours ("load following") timescales are collectively referred to in our study as *Shimmy* resources. Rapidly responsive loads can provide Net Load Following and Regulation services to system operators and reduce the need for traditional generation resources. These resources derive value by managing short-term fluctuations in net load. The Shimmy DR service type is separated into two key products: load following and regulation. Load-following DR resources are those capable of responding within five minutes of being dispatched, and enable load to participate in both the real-time energy and spinning reserves markets. Regulation DR resources must be capable of responding within four seconds, and enable load to participate in regulation markets.

Fixed behind the meter battery storage is in a sense "the ideal" DR technology. When combined with a battery, any load can provide flexible services that meet the requirements of the Shed, Shift, and Shimmy service types. Residential and Commercial batteries have potential to provide significant services to the distribution and transmission grid along with highly-valued site-level reliability and bill savings benefits. Unlocking that potential will require simplified procedures for interconnection and processes for presenting these resources to the wholesale markets as a resource.

We used the RESOLVE model to explore the value of Shimmy resources to grid operation. We found that Shimmy-type DR changes the dispatch profiles of battery storage. Without Shimmy-type DR, batteries provide load following and regulation. However, when other DR resources service these grid needs, batteries are instead dispatched to charge during hours with high renewable generation. Thus, Shimmy DR enables batteries to provide additional Shift-type DR rather than managing short-term variability in load, thereby increasing the value of battery storage.

The technology options for Shimmy are limited compared to Shed and Shift DR due to the requirements for fast-response capabilities and the need for installing advanced telemetry and control that can make some applications cost prohibitive. Figure 66 and Figure 67 below show that for the fastest response resources (Shimmy – Regulation) the main contributions based on our model assumptions come from lighting and commercial HVAC control, with the potential for significant contributions from residential behind-the-meter storage if the cost of storage is lower than we project. In Figure 66, the contributions of each sector are grouped, with

boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation. Load following is somewhat slower (5 minutes) and in addition to HVAC and lighting we expect contributions from industrial processes and pumping could be important opportunity areas in the future.

The relatively higher costs, when compared to the other DR service types, for Shimmy resources are driven by the automated controls, the telemetry requirements for granular energy measurement, and the real-time, or near real-time communication platform requirements, (i.e. RIGs or SEGs).

In Figure 67, the contributions of each sector are grouped, with boundaries between the sectors shown using black lines. The levelized cost estimates are net of expected market revenue and site-level co-benefits from automation.

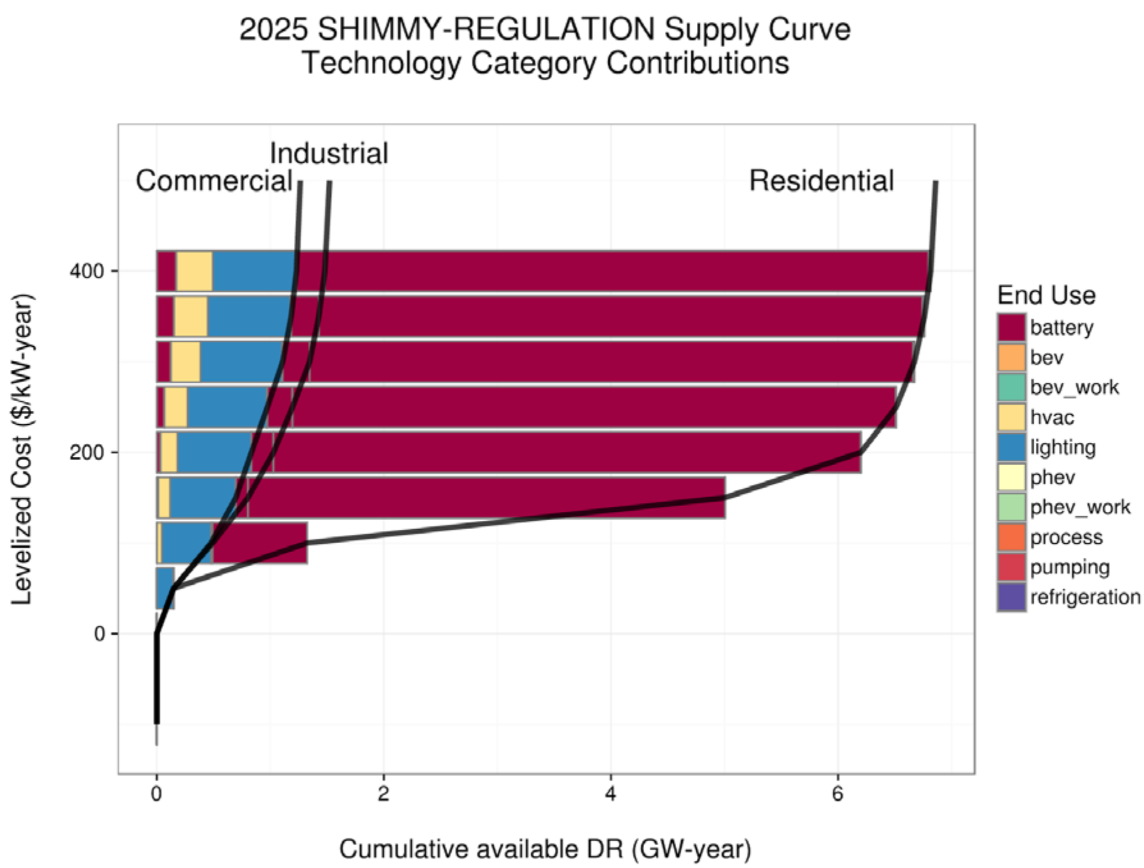

Figure 66: Shimmy (Regulation) DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

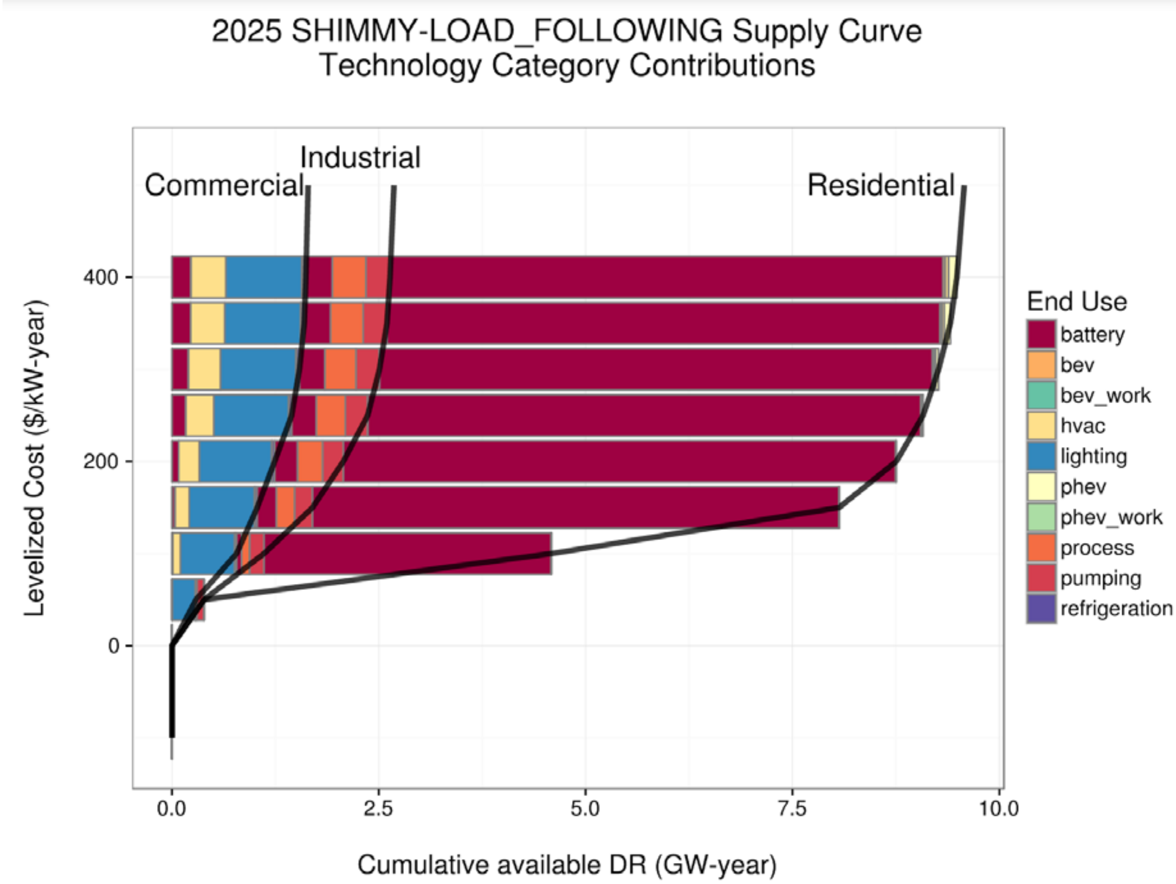

Figure 67: Shimmy (Load Following) DR supply curve in 2025, with contributions from end-use technology categories demarcated in stacked bar graphs.

5.6. The Value of Shimmy DR to the Grid

Shimmy is modeled as a reduction in the amount of load following and regulation that must otherwise be provided by non-DR resources. To limit complexity, we modeled equal megawatt amounts of load following and regulation in separate RESOLVE runs, even though the depth of the load following and regulation markets differ. That is, both parameters shown in Table 18 were modeled as taking the same set of values: 100, 300, and 600 MW.

Table 18: Shimmy parameters modeled in RESOLVE.

Shimmy Parameter	Description
MW of load following available by hour	Hourly amount by which a "Shimmy" DR resource offsets the load-following requirement for non-DR resources
MW of regulation available by hour	Hourly amount by which a "Shimmy" DR resource offsets the regulation requirement for non-DR resources

By providing load following and regulation, Shimmy resources free up other resources that currently provide these services to provide other grid services. In particular, the fast-response capabilities of batteries installed to meet the CAISO storage mandate mean they are often used to provide load following and regulation. However, Figure 68 illustrates that replacing batteries with other fast-response Shimmy DR resources enables batteries to instead charge during midday hours when renewable generation is high, thereby limiting renewables curtailment and decreasing the cost of meeting RPS goals. The latter scenario (with Shimmy DR) results in greater utilization of battery storage capacity.

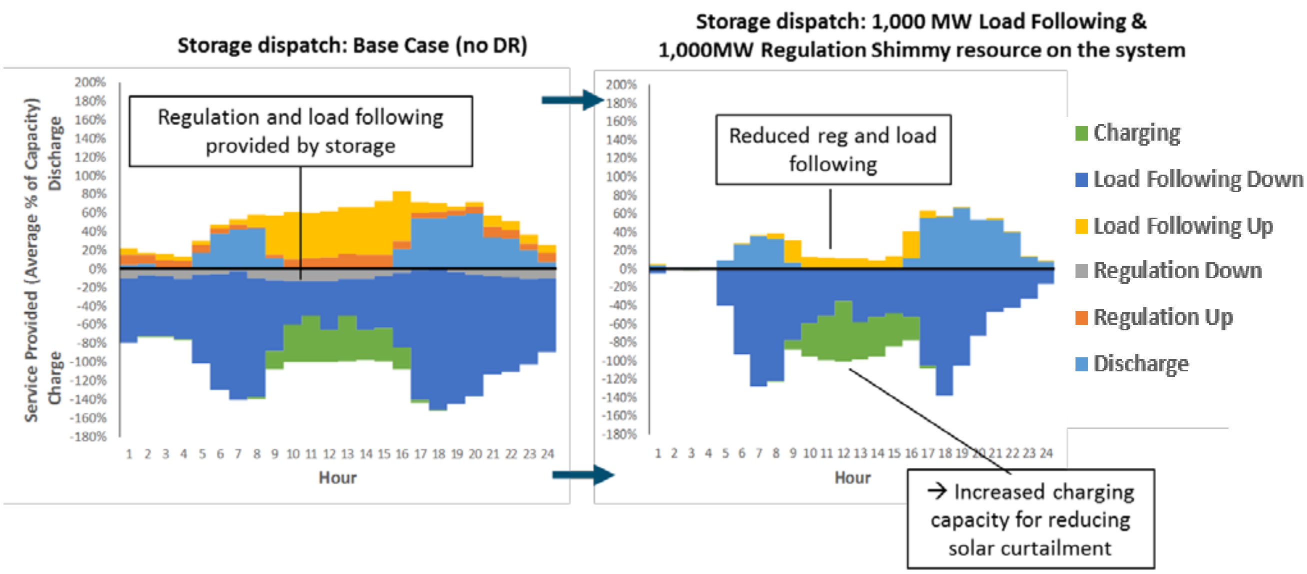

Figure 68: Storage services dispatched, without and with Shimmy resources.

Our modeling suggests that Shimmy resources have the potential to provide significant value to the CAISO system over the 2016–2030 timeframe. For example, we found a total of $21 million in benefits for 600 MW of load following in 2025, and $22.5 million in benefits for 600 MW of

regulation in 2025.

Just as the savings offered by Shift resources decline as the system becomes saturated with Shift, the savings per megawatt of Shimmy fall as we add more Shimmy resources, as shown in Figure 69 and Figure 70. Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown. The x-axis presents the available megawatts for load following DR, while the y-axis presents the savings to the system in $/kW-yr (2015). In Figure 70, we also see that 600 MW is close to the limit of the market depth for regulation, whereas the market for load following is deeper.

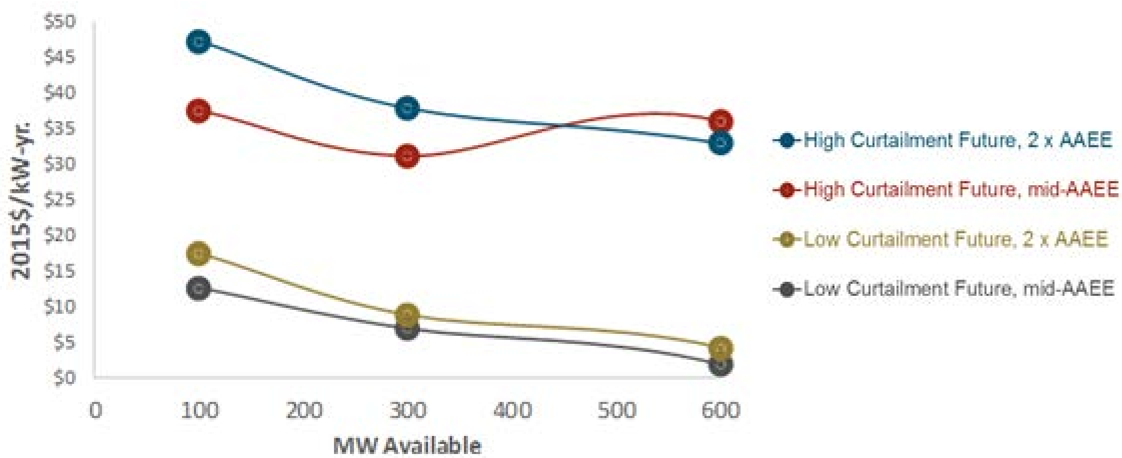

Figure 69: Load following marginal value as a function of availability.

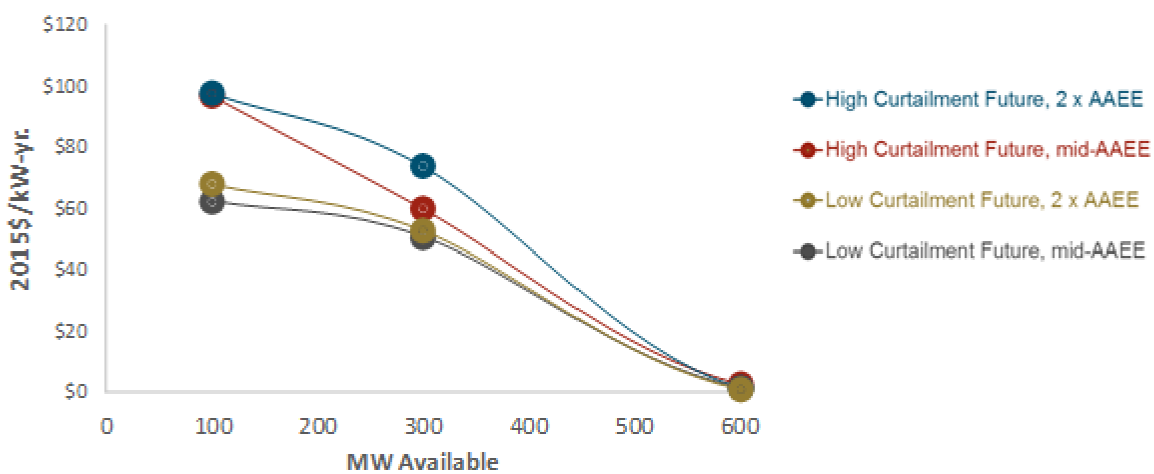

Figure 70: Regulation marginal value as a function of availability. Low-Curtailment and High-Curtailment scenario results for mid-AAEE and double the AAEE forecasts are shown.

Further, as was the case with Shift, reassigning total load following and regulation savings across the investment periods of 2016, 2020, 2025 and 2030 based on relative curtailment

amounts in these years shows high savings in 2025 and 2030. The results are shown in Figure 71 and Figure 72.

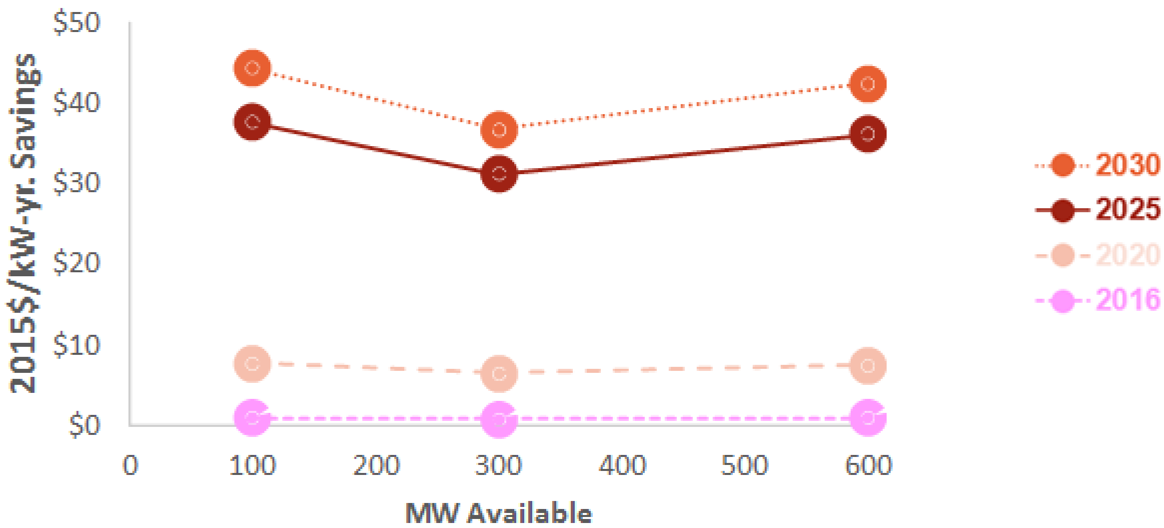

Figure 71: Annual marginal savings per kW of load following available by year, High-Curtailment, mid-AAEE scenario.

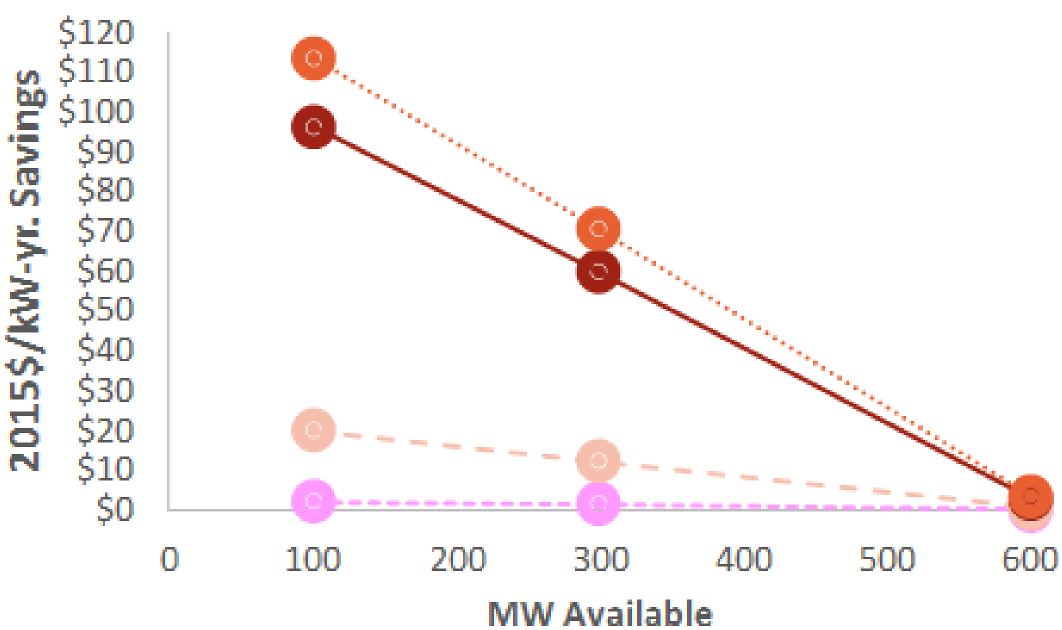

Figure 72: Annual marginal savings per kW of regulation available by year, High-Curtailment, mid-AAEE scenario.

5.7. Valuing Shimmy Service Type DR with Supply Curves and Levelized Demand Curves

Demand response potential supply curves for the 2025, mid-AAEE, rate mix 3 scenario are shown in Figure 73 and Figure 74 for load-following and regulation DR, respectively. In Figure 73, the RESOLVE demand curve intersects with the supply curve at ~350 MW, indicating the cost-competitive amount of Shimmy DR. Note that the levelized system value curves were not estimated beyond 0.6 GW of resource, but some supply curves do not intersect them. To estimate the box plots beyond the margins of the RESOLVE runs, we implemented a linear model fit that is shown by the dotted line. The fit is limited to the interval 0, 900 (extending the demand curve by about 40%). Case: Year 2025, Rate Mix #3, mid-AAEE trajectory. Shimmy load following resources are cost competitive for roughly 350 MW at about $40 per kW-year. Shimmy regulation DR is shown to be cost-competitive up to approximately $70 per kW-year in the medium scenario, resulting in a DR potential of about 350 MW across all three IOUs. As more DR is added, it becomes less valuable, resulting in a cost-competitive DR potential of 500 MW up to approximately $40 per kW-year in the high scenario.

These system-level values only describe the value of the Shimmy services to the grid, not the monetary value that would be adequate to compensate Shimmy participants that are participating in a frequently dispatched DR program. Our results do not intend to prescribe the level of compensation for participants in any way; rather, we have described the market value to the grid- the dollar value that is cost competitive for this service type resources as compared to alternative resources in the wholesale market. Our analysis was not intended to determine what compensation customers ought to receive for participating in each service type resource/program. In the cost estimates we include standard incentives that are on the same scale as those customers currently receive for Shed service.

In Figure 73, the RESOLVE demand curve intersects with the supply curve at ~ 300 MW, indicating the cost-competitive amount of Shimmy load following DR. The **GREEN** and **BLUE** colors in the lines (top) and bars (bottom) represent qualitative DR market scenarios. The dotted lines correspond to 1-in-2 weather and the solid lines are 1-in-10 weather years. The Low-Curtailment case (**RED**) and High-Curtailment case (**ORANGE**) horizontal lines represent the levelized demand curves. The equilibrium price is at the intersection of the levelized demand curves and the supply curves. Case: Year 2025, Rate Mix #3, mid-AAEE trajectory.

In Figure 74, the RESOLVE demand curve intersects with the supply curve at ~ 300 MW, indicating the cost-competitive amount of Shimmy Regulation DR, under the same parameters and scenarios as described above.

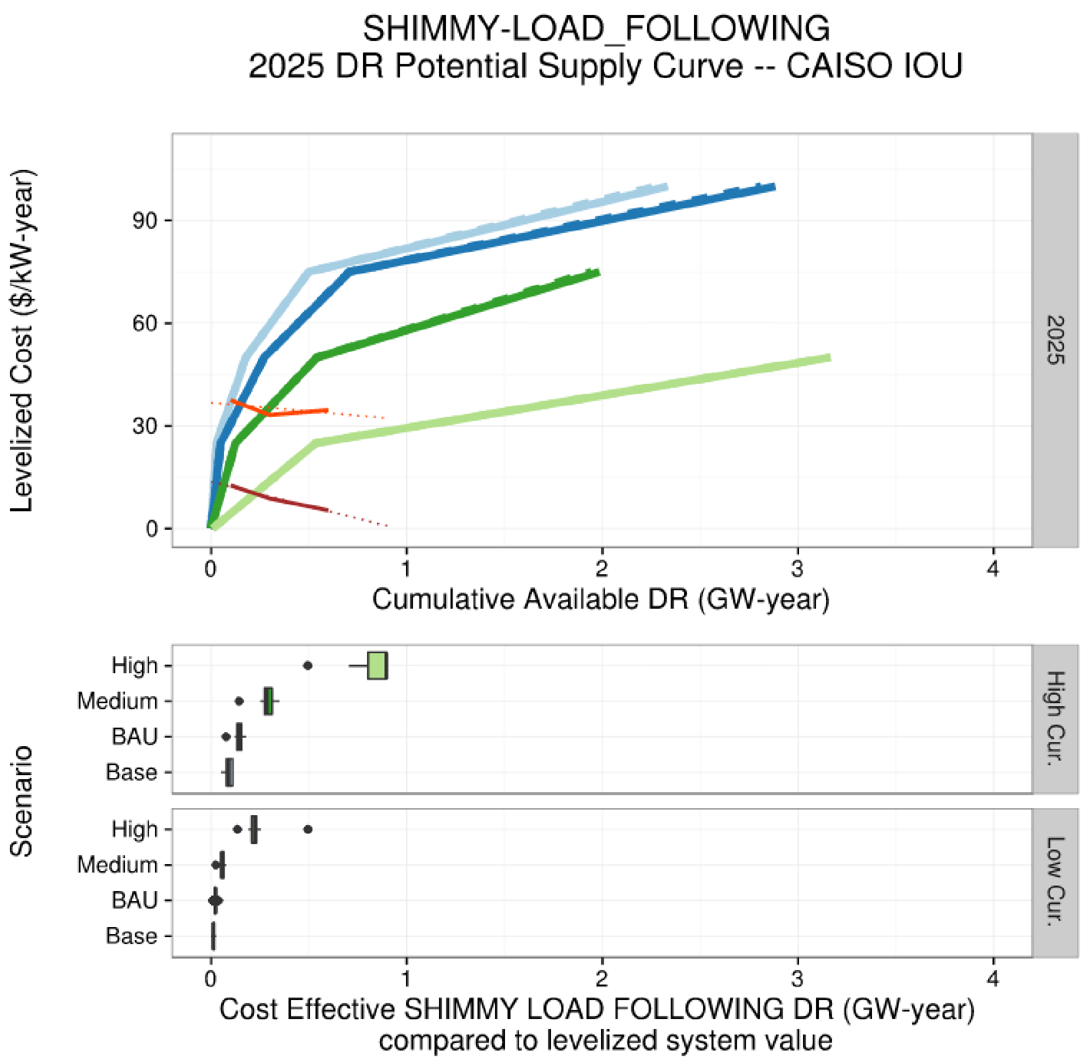

Figure 73: (top) 2025 Shimmy load following DR potential supply curve compared to the levelized demand curve; (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

Table 19 and Table 20 present the cost competitive prices and quantity for Shimmy Load Following DR from the DR Futures supply curves and the RESOLVE levelized demand curves, and represent the price at the intersection of each curve. For each service type, the costs and quantities are segmented by percentiles that capture the variance around the demand and supply curves' intersection. Table 22 and Table 23 show similar results for Shimmy Regulation DR. Table 21 and Table 24 shows an expanded set of results by IOU service territory, including 2020 and 2025 estimates for the expected cost-effective Shimmy DR.

Table 19: Levelized Price and Quantity of Cost Competitive Shimmy Load Following DR by Percentile (Low Curtailment Scenario)

Shimmy Load-Following DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System Payments
25th Percentile Price per kW ($)	$0	$0	$11	$0
25th Percentile Quantity (MW)	-	-	52	1,647
50th Percentile Price per kW ($)	$0	$0	$11	$0
50th Percentile Quantity (MW)	-	-	56	1,677
Mean Price per kW ($)	$4	$4	$12	$0
Mean Quantity (MW)	10	10	58	1,703
75th Percentile Price per kW ($)	$8	$8	$12	$0
75th Percentile Quantity (MW)	14	14	65	1,765

Table 20: Levelized Price and Quantity of Cost Competitive Shimmy Load Following DR by Percentile (High Curtailment Scenario)

Shimmy Load-Following DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System Payments
25th Percentile Price per kW ($)	$35	$35	$35	$0
25th Percentile Quantity (MW)	91	91	273	1,647
50th Percentile Price per kW ($)	$35	$35	$35	$0
50th Percentile Quantity (MW)	104	104	286	1,677
Mean Price per kW ($)	$35	$35	$35	$0
Mean Quantity (MW)	105	105	289	1,703
75th Percentile Price per kW ($)	$36	$36	$35	$0
75th Percentile Quantity (MW)	113	113	313	1,765

Table 21: Shimmy - Load Following potential (MW-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

Cost Framework	2020			2025		
	PG&E	SCE	PG&E	SCE	PG&E	SCE
Unadjusted Total	0	1	0	21	70	4
Net Total with ISO Revenue	0	1	0	21	70	4
Net Revenue + Site Co-Benefits	1	11	0	100	170	12
Net Revenue + Site + Distribution Co-Benefits	600	770	68	730	880	87

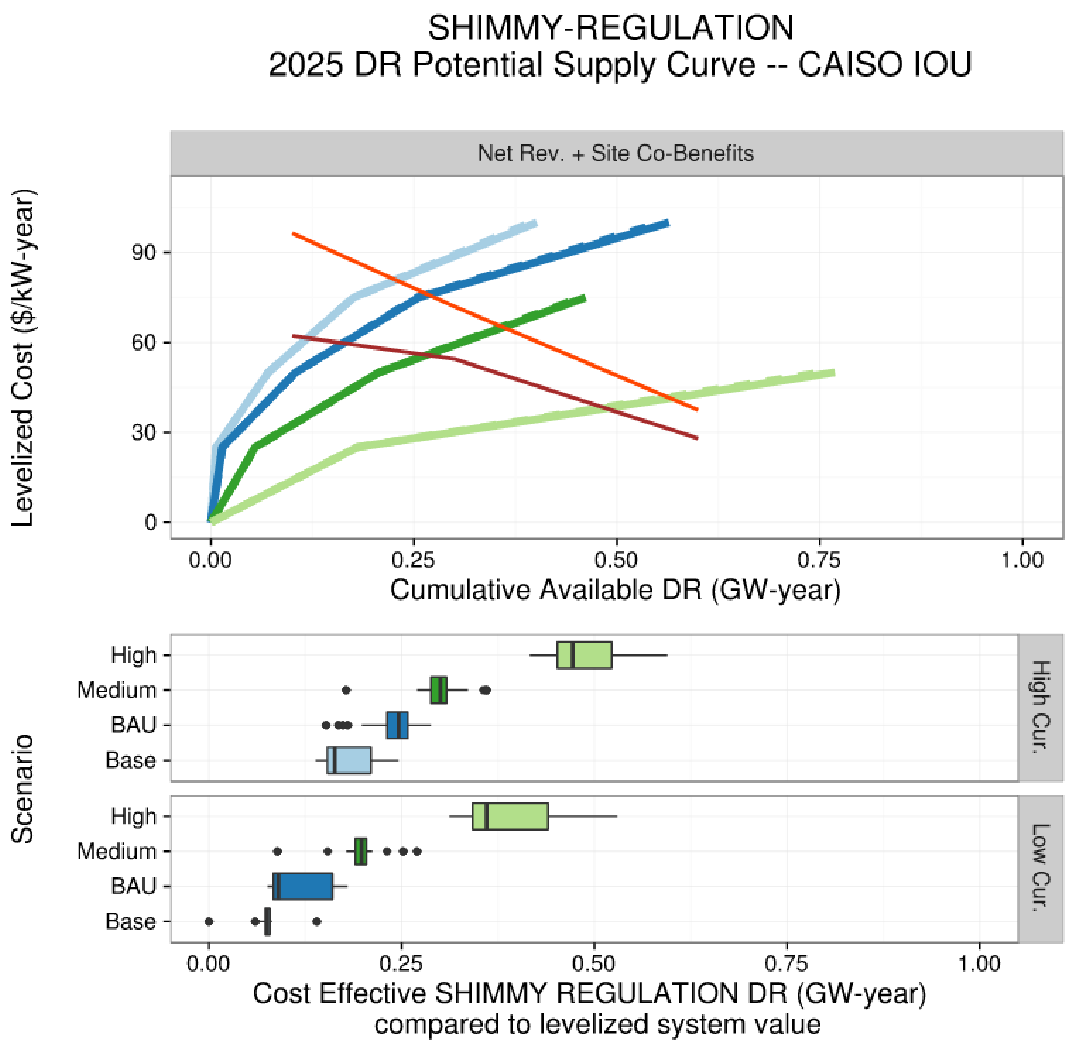

Figure 74: (top) Shimmy regulation DR potential supply curve results compared to the levelized demand curve, and (bottom) a range of cost-effective quantity based on a Monte Carlo uncertainty analysis of DR market and technology trends.

Table 22: Levelized Price and Quantity of Cost Competitive Shimmy Regulation DR by Percentile, Low Curtailment Scenario

Shimmy Regulation DR (Low Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System
25th Percentile Price per kW ($)	$50	$50	$45	$0
25th Percentile Quantity (MW)	94	94	189	848
50th Percentile Price per kW ($)	$52	$52	$47	$0
50th Percentile Quantity (MW)	98	98	195	878
Mean Price per kW ($)	$51	$51	$47	$0
Mean Quantity (MW)	96	96	193	885
75th Percentile Price per kW ($)	$54	$54	$50	$0
75th Percentile Quantity (MW)	102	102	204	918

Table 23: Levelized Price and Quantity of Cost Competitive Shimmy Regulation DR by Percentile, High Curtailment Scenario

Shimmy Regulation DR (High Curtailment Scenario)	Cost Framework			
Percentile Price & Quantity	Total	Net ISO Revenue	Net Revenue + Co-Benefits	Net Revenue, Co-Benefits + Distribution System
25th Percentile Price per kW ($)	$67	$67	$57	$0
25th Percentile Quantity (MW)	190	190	287	848
50th Percentile Price per kW ($)	$52	$52	$47	$0
50th Percentile Quantity (MW)	199	199	300	878
Mean Price per kW ($)	$51	$51	$47	$0
Mean Quantity (MW)	205	205	298	885
75th Percentile Price per kW ($)	$54	$54	$50	$0
75th Percentile Quantity (MW)	210	210	308	918

Table 24: Shimmy - Regulation potential (MWh-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

Cost Framework	2020			2025		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Unadjusted Total	0	0	0	64	130	11
Net Total with ISO Revenue	0	0	0	64	130	11
Net Revenue + Site Co-Benefits	0	13	0	100	180	18
Net Revenue + Site + Distribution Co-Benefits	260	480	51	320	530	65

5.8. Pathways to Market Participation for *Shimmy*

We estimate that Shimmy resources have the potential to provide significant but bounded value to the CAISO system over the 2016–2030 timeframe. Although Shimmy resources are of relatively high value per kW-year, they are bounded by the fact that system needs (and markets for ancillary services) are finite and based on the short-term variability on the electricity system. Fast-response DR resources that provide regulation and load-following add further value by freeing up storage resources to reduce renewable curtailment. The first 600 MW of load-following Shimmy is worth $21 million to the system, while the first 600 MW of regulation Shimmy is worth $22.5 million in the high-curtailment mid-AAEE case in 2025. The value of advanced DR will increase over time, as the CAISO system integrates additional renewables and curtailment becomes more significant during the midday hours.

The results from our levelized system value analysis indicate that about 350 MW of Shimmy Load Following Service resources are cost competitive under $50 per kW-year. For Shimmy Regulation DR, we found

Fast DR technology pilots:

Advanced end use control technologies that can provide fast response DR, such as variable frequency drives (VFDs) and pumps (VFPs) with DR control technologies should be piloted to determine their effectiveness in providing flexible and fast DR services, such as Shimmy Regulation and Load Following. Additional opportunities for these technologies include Shift and Shed service types. These technologies can be installed with commercial HVAC units and agricultural pumps, and could offer opportunities for customers to maintain comfort and production levels while providing flexible service to distribution and transmission systems.

roughly 450 MW to be cost competitive under $85 per kW-year.

The markets for regulation and load following DR are already playing out in various balancing authorities in the United States. For example, the PJM has a strong track record of successfully utilizing DR to provide Shimmy services.[33] The CAISO is working to establish rules and transaction requirements that would enable DR to more readily participate in AS markets, but these changes have not yet been realized. However, the current market prices for AS, in particular regulation up and regulation down, are depressed, and may not reflect future pricing trends for products participating in these markets in 2020 or 2025. Nonetheless, these low market prices do not readily encourage new market entrants for Shimmy service providers, since the telemetry and control technology costs can be quite high, given the fast transactive nature of the services. One theory for the reason AS prices are low is that they are a result of inter-market dynamics with the energy market, where prices have been depressed due to zero marginal cost renewables and low natural gas prices. AS price formation depends strongly on the opportunity cost for holding resources out of the energy market, and it is unclear how future energy and, AS markets will compensate generators. The opportunities for DR to obtain revenue for Shift is thus linked with broader trends in electricity markets.

Our study results indicate that there is economic value for Shimmy DR service types, that Shimmy can bring value to the CAISO system, and that DR technologies and potential customers exist today to provide that service. We estimate that the commercial customer class, with end uses that contain variable frequency drives/pumps or lighting controls will likely have the greatest potential to provide Shimmy DR. However, the market rules for DR participation in these markets, coupled with AS market prices, will continue to be barriers for DR market participants wishing to address the load-following and regulation needs of the grid with Shimmy DR services.

[33] See *PJM Manual 11: Energy & Ancillary Services Market Operations* at https://www.pjm.com/~/media/committees-groups/committees/mrc/20141120/20141120-item-06-residential-demand-response-draft-manual-11-revisions.ashx, and Cutter, Eric, et al. 2012. “Beyond DR – Maximizing the value of responsive load.” http://aceee.org/files/proceedings/2012/data/papers/0193-000395.pdf.

6. Key Takeaways

Advanced DR programs can help California meet the challenges of a high-renewables future. Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration.

6.1. Shape: Summary

We estimate that the effects of TOU and CPP pricing provide the equivalent of approximately 1 GW in Shed resource and 3 GWh/day in Shift resource. The average total daily load in 2025 is 600–700 GWh, so the Shape-Shift resource represents approximately 0.3 percent of load shifted. This result is based on estimates of how “static” TOU retail pricing structures are expected to change load, and how those modifications provide service equivalent to Shed and Shift service described above. With more significant investments in automatically price-responsive technology and exposure to real-time dynamic prices, it could be possible to achieve a significant portion of the dispatchable “Shift” resource we identify using price signals as opposed to conventional dispatch. A distributed price-responsive portfolio of loads that can shift may be more cost-effective than using centralized dispatch and payments through specific supply side markets for the “Shift” resource.

6.2. Shift: Summary

The Shift service type resource is by far the largest opportunity we identified for DR to provide system-level value for the future grid. With 20% of load shiftable, there is up to ~$700 million/year in benefits, and we estimate economically cost-effective DR up to ~10 percent of daily energy shifted in 2025 (for the high-curtailment, mid-AAEE scenario). Resources that shift load into high-curtailment hours can offer significant capital investment and operational cost savings by reducing renewable overgeneration (and overbuilding to meet a given set of clean energy goals). There are significant market and regulatory challenges, however, for capturing this value, since currently no market mechanism exists for services like Shift DR that are technology-driven and responsive to hour-to-hour and daily changes in the needs of the system. When considering potential revenue streams from the supply-side market, Shift could *potentially* earn revenues from energy, capacity, AS, and flexible capacity markets, but those markets are not currently organized to compensate a service like Shift DR, primarily because of the way those markets are presently defined. Shift resources could be dispatched on the majority of days in the energy market, as the value is fundamentally driven by daily solar generation in California. It would be a significant challenge to identify appropriate and accurate baselines against which to compare response when there are not days *without* Shift. Baseline issues are already challenging for Peak Shed DR that is only dispatched a handful of times a year. It is not

clear how Shift-type resources would fit in flexible capacity markets, and whether there would need to be restructuring of the compliance obligations to qualify aggregations of “shiftable” loads.

Because of these significant challenges to integration in the supply market, LBNL recommends the Shift-type resources be handled in the retail market, through pricing programs and automated DR controls. This comes with its own challenges around incentivizing investment in control technology and customer adoption, but it could accomplish the same fundamental dynamics with much more transparent market integration. We note here that Shift resources do not necessarily need to be fast responding. The daily need for shifting is relatively predictable, and a day-ahead price schedule may achieve significant fractions of the ideal shift pattern. The current stock of conventional automated DR technologies are fast enough to respond to these signals, and may be candidates for parallel use or low-cost upgrades compared to new DR sites. These co-developing market, policy, and technology systems for Shifting could also result in some hybrid approach that mixes price response with awarded flexible capacity credits based on an expectation of future response as buydown for appropriately specified control technology.

6.3. Shed: Summary

Our research suggests that a large potential resource of Shed DR exists in 2025, ranging from 2 to 10 GW, depending on the technology costs and performance scenario, when evaluating the value of DR using the $200/kW price referent. However, as system capacity is overbuilt in pursuit of achieving the 50 percent RPS, there is far reduced need for system-level peak-shed DR by 2025. The RESOLVE model demand curves estimates the value of Shed to be at $4/kW-yr, far below the price referent value of $200/kW-yr.

Based on an expected future generation fleet consistent with long-term procurement planning and reasonable facility retirement schedules, the RESOLVE model estimates found Shed to have a very low system-level value compared to price referent values that are often cited: the availability of 10,000 MW of Shed resource would save the CAISO system only $31 million in 2025, or about $4/kW-yr. Our system-levelized value analysis (which examined the equilibrium price at the intersection of the supply and demand curves for the DR service types) found that there would be 100–400 MW of cost-competitive Shed DR resources in 2025 that could compete based on energy market participation.

The vast majority of Shed DR resources’ costs exceed their value to the grid, but it is notable that accounting for possible service to local distribution system capacity needs can flip the potential back to a significantly large value. Half of the Shed DR resources in California are in one of three local load pockets, where a higher price referent may be called for based on the binding need in the future to maintain reliability with generation investment. When we included a set of possible distribution system values as a portfolio element, we found that 1–4 GW of

Shed resource may be cost-effective for avoiding or deferring feeder and substation-level investment. The technology area with the largest increases in potential was residential behind-the-meter batteries, which become cost-effective when including site-level co-benefits, namely, from reduced energy charges from TOU pricing and/or coincident demand charges. These dynamics are repeated across other DR resource types. We note as well that local capacity Shed resources could still provide significant value as well in generation and transmission constrained areas – up to 4 GW in the Medium DR scenario.

These findings challenge the conventional wisdom of focusing solely on peak capacity DR programs in California. For years, the greatest need to the electricity grid was managing peak demand; however, with the mass implementation of renewable generation and mandates to meet even higher RPS standards of 50 percent, the challenges of the grid have shifted away from peak capacity shortfalls, thus drastically reducing the need for Shed-type resources to serve the CAISO balancing authority over the coming decade and beyond. This suggests that the focus on system Sheds should be redirected to focus on local and distribution-system needs, and that the control technology and business relationships in place could be the foundation of new portfolios that combine targeted and/or fast Shed with Shift.

6.4. Shimmy: Summary

We estimate that Shimmy resources have the potential to provide significant but bounded value to the CAISO system over the 2016–2030 timeframe—significant in having a relatively high value per kW-year but bounded by the fact that the size of need (and markets for ancillary services) are finite and based on the short-term variability on the electricity system. This fast-response DR that provides regulation and load-following can create value by freeing up storage resources to reduce renewable curtailment. The first 600 MW of load-following Shimmy is worth $21 million to the system, while the first 600 MW of regulation Shimmy is worth $22.5 million, both in the high-curtailment, mid-AAEE case in 2025. The value of advanced DR will increase over time, as the CAISO system integrates additional renewables, and curtailment becomes more significant during the midday hours.

The study's levelized system value analysis indicate that ~300 MW of Shimmy Load Following Service resources are cost competitive under $50/kW-yr. For Shimmy Regulation DR, we found ~300 MW to be cost competitive under $85/kW.

The markets for regulation and load-following DR are already playing out in various balancing authorities in the United States, with the PJM having a strong track record of success utilizing DR to provide Shimmy services.[34] The CAISO has been working to establish rules and

[34] See *PJM Manual 11: Energy & Ancillary Services Market Operations* at

transaction requirements to enable DR to more readily participate in AS markets, but this has not yet been realized. However, the current market prices for AS—in particular, regulation up and regulation down—are depressed, and currently may not reflect future pricing trends for products participating in these markets in 2020 or 2025. Nonetheless, these low market prices do not readily encourage new market entrants for Shimmy service providers, since the telemetry and control technology costs can be quite high, given the fast transactive nature of the services.

Our study results indicate that there is economic value for Shimmy DR service types, that Shimmy can bring value to the CAISO system, and that DR technologies and potential customers exist today to provide that service. We estimate that the commercial customer class, with end uses that contain variable frequency drives/pumps, or lighting controls, will likely have the greatest potential to provide Shimmy DR. However, the market rules for DR participation in these markets, coupled with AS market prices will continue to be barriers for DR market participants wishing to address the load-following and regulation needs of the grid with Shimmy DR services.

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https://www.pjm.com/~/media/committees-groups/committees/mrc/20141120/20141120-item-06-residential-demand-response-draft-manual-11-revisions.ashx, and Cutter, Eric, et al. 2012. "Beyond DR- Maximizing the value of responsive load". http://aceee.org/files/proceedings/2012/data/papers/0193-000395.pdf

7. End-Use Enabling Control Technologies

Our bottom-up model for estimating DR potential is based on the sum total of a range of different end-uses, combined into a portfolio of resources on the future grid. The results should be considered as one of many possible futures for DR, and in aggregate defines a reasonable estimate of potential, but not a prescriptive or definitive set of technology. Put simply, the model is not designed to pick technological winners but is designed instead to identify what is possible overall, and points towards likely but not certain trends in where DR resource can be achieved. We expect that the particulars of specific technology options --- smart thermostats in commercial buildings, dynamic EV charging, industrial process control, and others --- will end up either more or less favorable as the technology and implementation strategies evolve.

During the study we worked to understand the current and potential future technology landscape. A key element of this was engagement with our technical advisory committee and deep-dive interviews with a dozen industry experts from utilities, energy service providers, and DR technology manufacturers to solicit information on current trends, barriers, and opportunities for advanced DR in the next decade. In this section we synthesize the findings and trends on key enabling technology areas, and provide a dive into the details of our model results for end-use categories.

7.1. Existing and Emerging DR technologies

Our study evaluated the DR potential for a number of different end uses and technologies. This set of end uses was limited to manage the scope of the study and we recognize that there are a number of end uses, such as major household appliances (e.g. refrigerators, dryers, and plug loads) that could provide additional DR services but were not included in this Phase of the study. Below we discuss the existing and emerging technologies that were included in this study and a brief discussion of residential hot water heaters, which were not specifically modeled in this study phase.

7.1.1. Cost competitive DR technologies

The cost competitive prices and quantities presented in this section were developed using the DR Futures supply curves and the RESOLVE levelized demand curves. In Table 25, the costs for each service type are segmented by percentiles that capture the variance around the intersection of the demand and supply curves for each service type. Note that the price for Shed is zero, meaning that there is no cost competitive value for Shed services for any of the end uses. In other words, Shed services are not economically viable because there is adequate capacity from existing and less expensive generation resources.

The unit prices in Table 25 are representative for all of the end uses and customer sectors. Each

technology/end use DR service type quantity (MWs and MWhs) described in the end use specific sections below is the quantity of DR available at the prices presented in Table 25.

Table 25: Competitive Levelized Costs for DR service in kW-yr for Shed and shimmy services, and in kWh-yr for Shift services.

Commercial Lighting: Competitive Levelized Costs	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Levelized Price per unit of DR	kW-yr	kWh-yr	kW-yr	kW-yr
25th Percentile Price	$0	$28	$35	$57
50th Percentile Price	$0	$29	$35	$60
75th Percentile Price	$0	$30	$35	$62

7.1.2. Industrial processes

Industrial processes are foundational for current-day DR programs and we expect will continue to be high-value, low-cost opportunities for load flexibiilty in the future. This sector is well understood from the perspective of conventional “Shed” DR, and much of that practice could translate well to locally-focused Sheds. More frequent load shifting would require structural adjustements to the scheduling of facilities, and the kinds of Shifts that are suggested by our work (from night into day) could be well-matched to the preferences of the labor force to complete work during the day,

Industrial customers are not the same as commercial and residential, and one approach does not fit all (or sometimes even two) customers. We heard from stakeholders in the sector that there are challenges with maintaining facility autonomy and concerns that the kind of “every day” DR from Shimmy and Shift may not be well suited to the kinds of operational strategies that have worked for Shed DR in the past. Careful work to understand the needs in the industrial sector for transitioning from conventional to advanced DR will be important to unlock the potential we estimate, shown in Figure 75 below across a range of resource types. The left side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the “medium” DR case in 2025, with 1-in-2-weather mid-AAEE efficiency trajectory and Rate Mix #3.

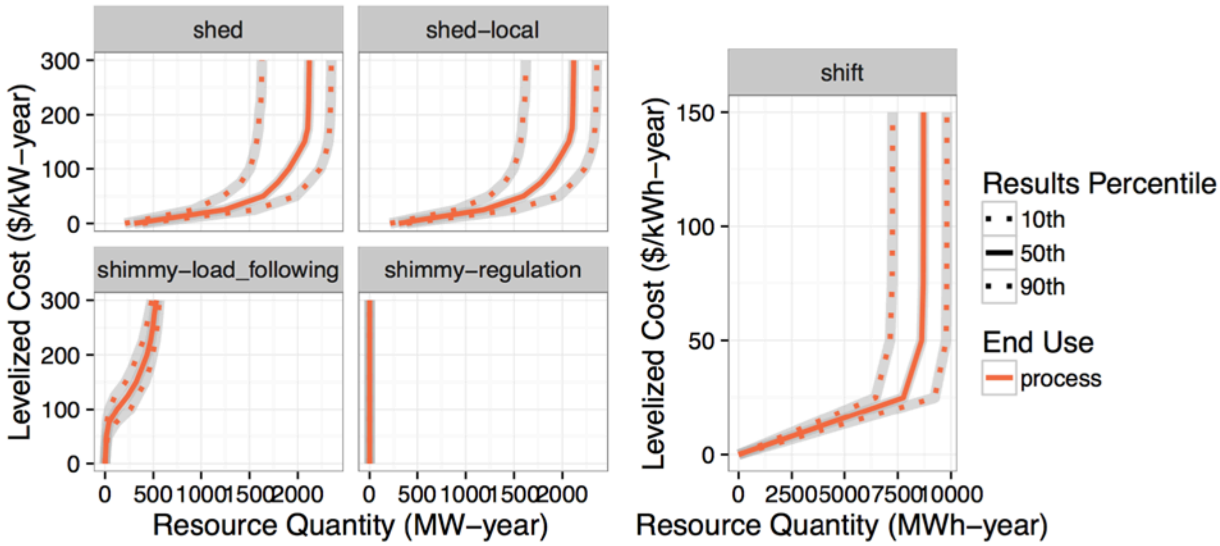


Figure 75: Industrial process end-use level supply curves.

Table 26 below indicates the cost competitive quantity of DR from Industrial processes for each of the service types. Shift and Shimmy Load Following are the only DR service resources that are cost competitive for Commercial HVAC, which can provide 7,978 to 8,017 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr. Advanced end uses such as VFD with ADR can provide 11 MW-year of cost competitive Shimmy load following service to the grid. The levelized costs for load following services is $35/kW-yr. Although there is 827 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 26: Quantity of cost competitive Industrial Process DR by MW-yr for Shimmy and MWh-yr for Shift.

Industrial Process End-Uses: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	827	7,978	11	0
50th Percentile Quantity	827	7,998	11	0
75th Percentile Quantity	827	8,017	11	0

7.1.3. Residential HVAC

Residential HVAC is one of the most promising end-uses for delivering peak capacity DR when needed, but controls that facilitate fast response DR are still emerging. Today, there are some HVAC controls that could potentially provide service with a five minute signal, but would need to be aggregated to produce reliable DR service, because the optimal compressor runtime ranges from 7-10 minutes, and anything less than that could cause discomfort to the customer. In order to aggregate the impacts from HVAC units that provide fast DR service, there is a need to

collect compressor runtime information in real time, according to several survey participants.

In Figure 76 below, the left side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the “medium” DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3. Table 27 below indicates the cost competitive quantity of Residential HVAC DR for each of the service types. Shift is the only DR service resource that is cost competitive for residential HVAC, with cost ranging from $28-$30 per kWh-yr and providing 32-43 MWh-year. Although there is 2 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

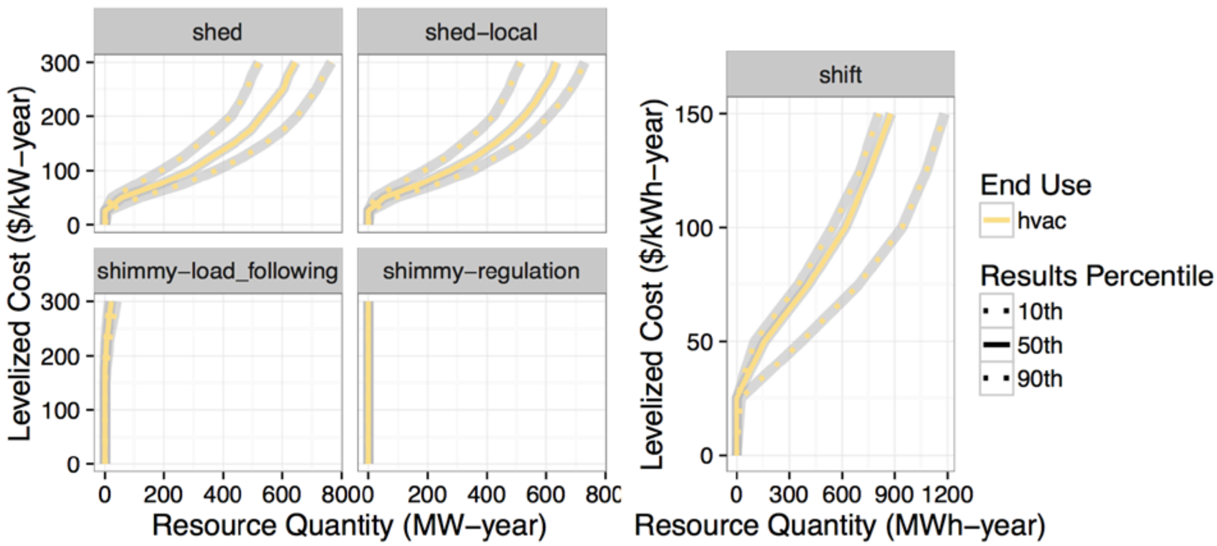


Figure 76: Residential HVAC end-use level supply curves.

Table 27: Quantity of cost competitive Residential HVAC DR by MW-yr for Shimmy and MWh-yr for Shift.

Residential HVAC: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	2	32	0	0
50th Percentile Quantity	2	38	0	0
75th Percentile Quantity	2	43	0	0

7.1.4. Commercial Variable Frequency Drives (VFDs)

VFDs in commercial HVAC have the potential to provide fast DR but these resources haven't been piloted in the IOU service territories, according to survey respondents. Aggregation of commercial HVAC units with VFD, coupled with "plug-and-play" access to markets, could provide Shed, Shape, and Shimmy services to the grid. The functionality of the VFDs allows for full automation technology to maintain customer comfort levels, limit disruption to operations, and provide fast response DR service to the grid. These technologies should be piloted to test scalability, interconnection, and performance for distribution and transmission system services.

DR-enabled variable frequency drives (VFDs) in Commercial HVAC are an extremely responsive technology that can provide DR services at the system and local level. These technologies should be piloted to test performance and scalability for transmission and distribution system services.

In Figure 77 below, the left side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3.

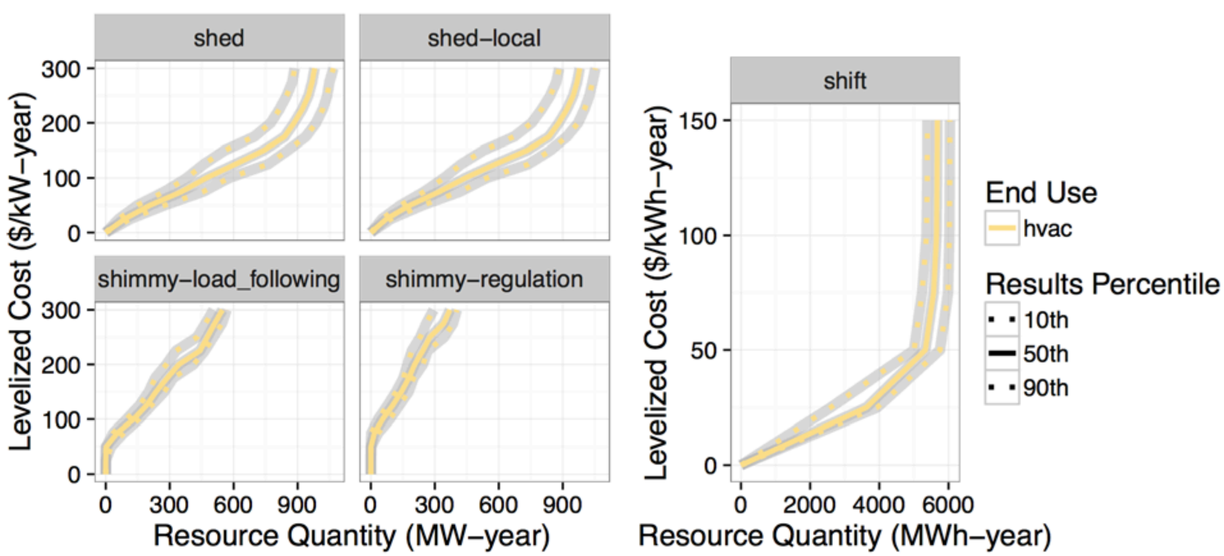


Figure 77: Commercial HVAC end-use level supply curves.

Table 28 below indicates the cost competitive quantity of Commercial HVAC DR for each of

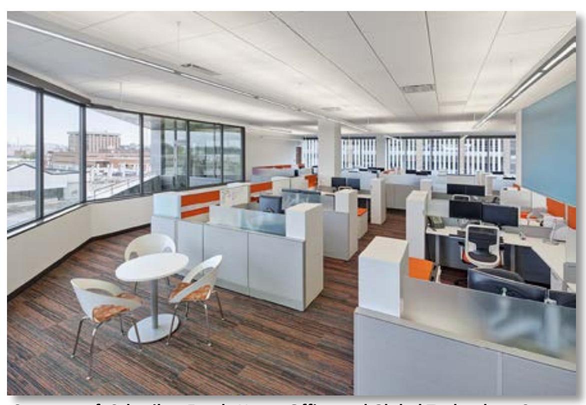
the service types. Shift, Shimmy Load Following and Shimmy regulation are the DR service resources that are cost competitive for Commercial HVAC, which can provide 3,643 to 3,749 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, capitalizing on the thermal load capacity. Advanced end uses such as VFD with ADR can provide cost competitive Shimmy service to the grid of around 3 MW-year for load following and between 6-9 MW-year of regulation service. The costs for load following services is $35/kW-yr and for regulation, the costs range from $57-$62 kW-year. Although there is 59 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 28: Quantity of cost competitive Commercial HVAC DR by MW-yr for Shimmy and MWh-yr for Shift.

Commercial HVAC: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	59	3643	3	6
50th Percentile Quantity	59	3698	3	7
75th Percentile Quantity	59	3749	3	9

7.1.5. Commercial Lighting

While industry stakeholders agree that commercial lighting as an end use has a huge potential to provide DR services to the grid, most acknowledge that there are significant barriers to realizing that potential. Stakeholders report that commercial and industrial customers have not been receptive to lighting upgrades that include DR technologies, primarily because the existing lighting stock has either been addressed with retrofits in the last decade, the upgrades are disruptive to business, and/or the costs for lighting DR control technologies can be prohibitive. This current condition is changing with the widespread adoption of lower cost, more efficacious LED luminaires networked with wireless controls.



Courtesy of: Schreiber Foods Home Office and Global Technology Center, HGA Architects and Engineers, Darris Lee Harris Photography

In Figure 78 below, the set of plots show Shed and Shimmy, and there is no resource available for Shift (no storage inherent in lighting). The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the “medium” DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3.

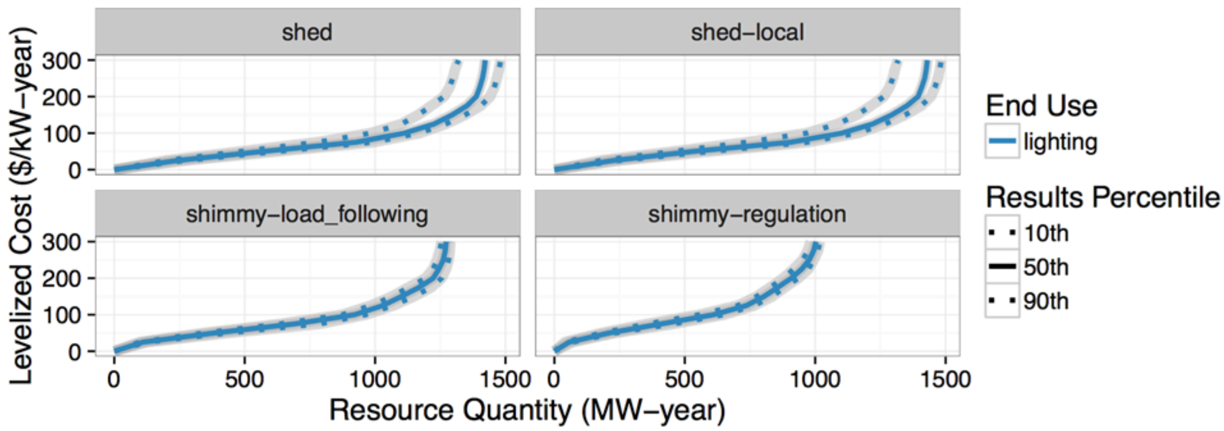


Figure 78: Commercial Lighting end-use level supply curves.

Table 29 below indicates the cost competitive quantity of Commercial Lighting DR for each of the service types. Shimmy load following and Shimmy regulation are the DR service resources that are cost competitive for Commercial Lighting. Advanced end uses such as ADR controlled luminaires can provide 216-221 MW-year of cost competitive Shimmy service to the grid for load following and between 265-303 MW-year of regulation service. The costs for load following services is $35/kW-yr and for regulation, the costs range from $57-$62 kW-year. Although there is 156 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 29: Quantity of cost competitive Commercial Lighting DR by MW-yr for Shimmy and MWh-yr for Shift.

Commercial Lighting: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	156	N/A	216	265
50th Percentile Quantity	156	N/A	218	284
75th Percentile Quantity	156	N/A	221	303

7.1.6. Industrial Wastewater processes and pumping

This end use holds significant potential because of the resource size and energy demand at each site, but is generally always in operation which makes it difficult to curtail. There are technologies available today that offer variable speed pumps and drives that could provide faster DR services, but the costs for upgrading equipment and potential downtime create barriers for these facilities. In Figure 79 below, the left-side set of plots show Shed and Shimmy, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the “medium” DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory and Rate Mix #3.

7.1.7. Agricultural Pumping with Variable Frequency Pumps

Variable frequency pumps (VFPs) technologies control the rotational speed of an electric motor by controlling the frequency of the electrical power supplied to the motor. They are proven to substantially reduce energy use. Irrigation pumps with VFPs and automation have the best potential to participate in DR and permanent load shifting while requiring limited customer interaction with the controls. Nearly all irrigation pumps used for agriculture in California are manually controlled.[35] In addition to upgrading pumps to the efficient VFDs, in order to be automated, the Agricultural customer must have controls with access to the internet so they can receive price signals or DR event triggers from the aggregator or utility. The automated controller at the pump can receive the DR signal and adjust the irrigation schedule according to the DR event. This automation can permit ramping pumping up during off peak hours and down during on peak hours with no manual customer interaction. While these pumps are available today and

[35] Marks, et.al. Opportunities for Demand Response in California Agricultural Irrigation: A Scoping Study. January 2013. LBNL. https://esdr.lbl.gov/sites/all/files/LBNL-6108E_0.pdf

could provide fast DR services, the costs for upgrading equipment can be a confounding factor for many agricultural industrial customers. It is also possible that agricultural customers are not aware of EE and DR incentives offered by the CA utilities, or that the installation would cause and interruption to service that is undesirable for production.

Our estimates for Agricultural pumping were based on actual 2014 weather and customer load data. We did not adjust based on precipitation or other factors in our estimates for agricultural pumping DR potential, and 2014 was in the midst of a long-term drought. Future estimates based on a range of weather years could be useful for planning in the context of colinearity with hydroelectricity availability.

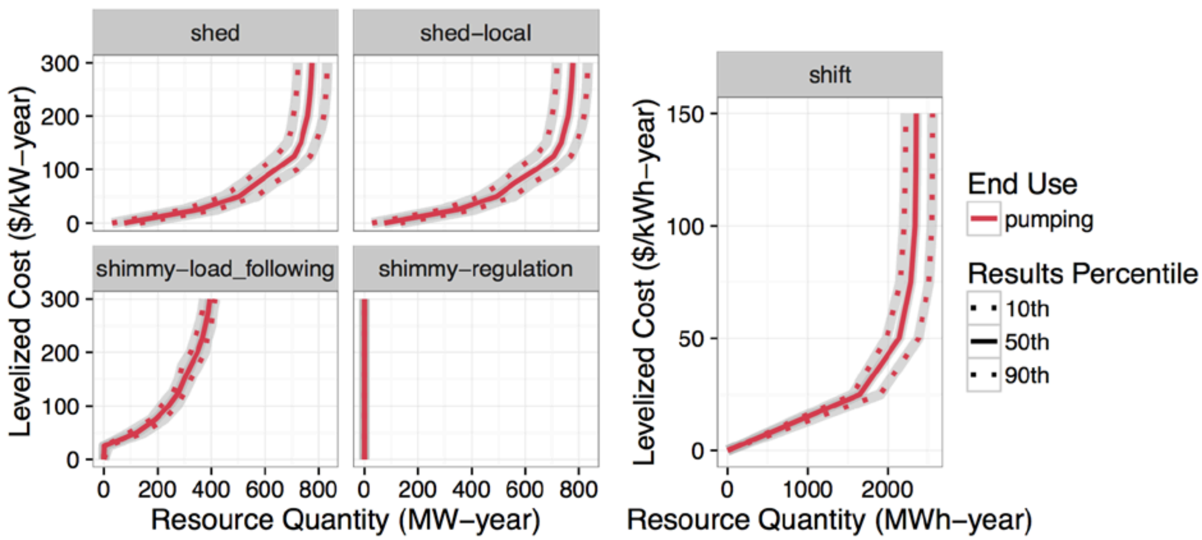


Figure 79: Water pumping end-use level supply curves for the industrial and agricultural sectors.

Table 30 indicates the cost competitive quantity of Industrial Waste Water and Agricultural Pumping DR for each of the service types. Shift and Shimmy load following are the DR service resources that are cost competitive for Industrial WW and AG Pumping which can provide 1,768 to 1,792 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, Advanced end uses such as VFP with ADR can provide 49- 51 MW-year of cost competitive Shimmy load following service to the grid. The costs for load following services is $35/kW-yr. Although there is 240 MW-year for Shed available, we find that it is not cost competitive as compared to other resources on the grid.

Table 30: Quantity of cost competitive Industrial Waste Water and Agricultural Pumping DR by MW-yr for Shimmy and MWh-yr for Shift.

Industrial Waste Water and Agricultural Pumping: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	240	1768	49	0
50th Percentile Quantity	240	1780	50	0
75th Percentile Quantity	240	1792	51	0

7.1.8. Residential Water Heaters & Pool Pumps

Market barriers include customer adoption of DR technology controls for these end uses, pool pumps in particular. The controllers can provide fast and slow DR services, but the challenge has been customer enrollments into DR programs, and when coupled with low penetration of these end uses in the IOU service territories, this has been a confounding factor. Although we included pool pump end use technologies in our analysis, there was no cost competitive DR available from the resource.

Water heaters were not explicitly modeled in this study, but could potentially offer shift and shimmy services to the distribution and transmission systems. At the time of this study, we are not aware of any pilots for electric or heat pump hot water heaters in CA. We estimate that the penetration of this residential end use is around 15% for the IOU service territories. This end use load can act as thermal storage, and when aggregated could provide flexible and fast DR services. Additionally, electrification of this end use (retrofitting existing gas water heaters with electric) could increase the potential for this resource to provide thermal storage for shiftting load and/or providing shimmy services, especially in constrained service areas. We recommend that water heater DR technologies be piloted to determine the effectiveness of this end use in providing Shift and fast DR services.

7.1.9. Data centers

Strategies for data centers to shift or shed short term energy needs include (1) virtualization[36], by which loads are consolidated, (2) colocation[37] where operators move loads to an offsite location when time of use electric pricing is lower and (3) changes directly impacting facility operations such as lighting and HVAC (curtailment or precooling). Many workloads, or batch processes that are energy intensive, in data centers are delay tolerant and can be scheduled to finish before a scheduled deadlines. This enables significant flexibility for managing power demand. Data centers are already highly automated, thus are excellent candidates for Shift services.

Stakeholders agree that data centers have potential to provide DR services, but assert that there is little chance for utility operated automation at these sites due to the highly sensitive nature of operations and reluctance of data center operations to relinquish control of batch processes or server room cooling.

7.1.10. Refrigerated Warehouses

Refrigerated warehouses and cold storage facilities could provide several hundred MWh of Shift DR to the system without compromising the quality of products stored in these facilities. Several energy service providers (ESPs) have developed technologies specifically for cold storage facilities and are currently provide EE and DR services for a number of companies around the country. These facilities can provide curtailment services, but more importantly, their thermal load is an excellent resource for absorbing renewable solar energy during the day, by shifting cooling cycles to reduce the temperature in the facility during the day, and then shutting off electricity to refrigeration units during off-cycles to save energy, thus holding the temperature. Full automation technologies are readily available and can optimize energy operations for DR and EE for these facilities.

Table 31 below provides details on the costs and quantity of DR (in MW or MWh) services

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[36] Data center virtualization involves using software to virtually host processes across a server network, rather than having specific servers dedicated to particular tasks. This enables more uniform loading on server infrastructure, can improve energy efficiency, offers opportunities for redundancy, and lets processes scale up and down with less difficulty.

[37] A colocation is a data center facility in which a business can rent space for servers and other computing hardware.

from refrigerated and cool storage facilities. The cost competitive price for shift resources is approximately $30/kWh at a quantity of 207 MWh-yr. These facilitates can also provide cost competitive Shimmy load following service of around 6 MW-yr at a cost of $35/kW-yr. Our analysis indicates that currently, there is no cost effective Shed or Shimmy- regulation services for refrigerated warehouses.

Table 31: Quantity of cost competitive Commercial Refrigerated Warehouses DR by MW-yr for Shimmy and MWh-yr for Shift.

Commercial Refrigerated Warehouses: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	8	206	6	0
50th Percentile Quantity	8	207	6	0
75th Percentile Quantity	8	209	7	0

Plug and Play DR: *The ability to acquire technology from different vendors, specify the communications interface between products and have all such products install and work together easily and quickly is known as "plug-and-play". This concept is a critical assumption that we make in the study; enabling technologies will be able to communicate and interface together to provide end use control and response to signals from an aggregator, consumer, or utility. Over the next decade, we assume that a "plug-and play" grid will continue to evolve and that communication standards will improve to make device connection and response easier and quicker than is currently the case today. This can be accomplished through coordination of standards with organizations like the OpenADR Alliance. The standards and requirements for telemetry of distributed DR resources can be simplified to allow for great access to the wholesale market in California.*

7.1.11. DR and Storage

Shift and Shimmy DR depends fundamentally on energy storage to operate. Some DR storage is based on the thermal capacity of buildings and refrigerated goods, and others on flexibility in scheduling. There are also two key emerging technology areas where electrochemical battery storage is a key driver: behind-the-meter fixed batteries and electric vehicles.

Behind-the meter Battery Storage

One of the key findings in our study is that the potential for behind-the-meter battery storage can significantly shift the capabilities of sites to present demand response potential to grid operators. Advances in the cost and performance of modern batteries with lithium-based chemistry could significantly contribute to the resource pool of DR technologies. Because batteries are inherently scalable, there are not the same physical limits on flexibility resource as controllable load DR. This means that if the cost of batteries (net any other revenue streams) falls below the cost-effective threshold level for DR services, it is the long-run average cost of storage that sets a “price referent” for other resources to compete against. The outcomes in Figure 80 reflect this dynamic, that there is little-to-no “very low cost” resource below $50/kW-year or /kWh-year but a large resource base that is only limited by the assumptions of our analysis above that level.

Currently, rules and requirements for interconnecting behind the meter (BTM) storage to the transmission system has been a barrier for bringing these resources to the CA wholesale markets. Stakeholders have indicated that the current telemetry requirements are costly, and in some cases, BTM resources require three meters to participate in the supply side markets. In our analysis of BTM storage, we assumed that the telemetry and communication costs would be consistent with other advanced technologies, (i.e. a single meter and communication platform at the site) and did not assume that in 2020 or 2025 that the BTM storage resources would require multiple meters. Therefore the BTM storage DR potential to be realized in 2025, the telemetry and communication requirements should be examined in an effort to address this barrier.

For the purposes of this study, we have defined a notional, example fleet of behind the meter batteries with reasonable capacity given trends in the battery market. If the full cost of batteries is to be covered by capacity payments and limited participation in the energy market, the supply curves in show that while the potential resource is large, there is limited cost-competitive DR from batteries. Nearly the full potential resource is above $100/kW-yr. Figure 80 below indicates the quantity of available DR from batteries, however, the cost competitive price for each kW and kWh of the Shift and Shimmy resource ranges between $28 to $62/kW. Therefore, the DR potential for batteries is above the economically competitive value. Our findings indicate that there is no cost competitive DR from commercial batteries; all availability comes from the industrial and residential sectors. Breakthroughs in battery cost and market offerings could reduce the levelized cost of capacity and dramatically shift the quantity of cost-competitive DR available from batteries.

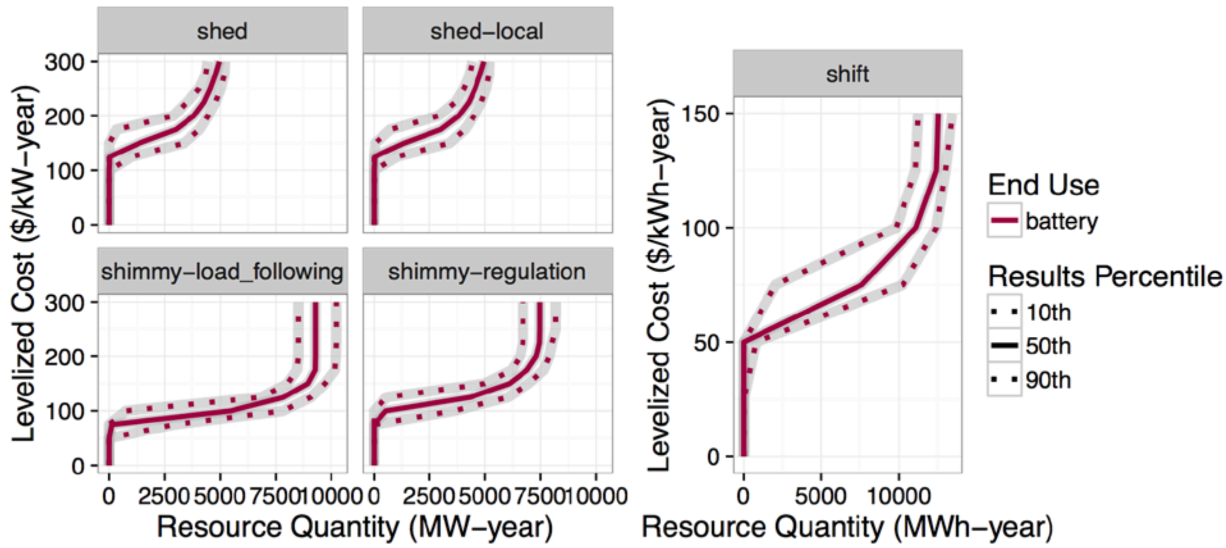

Figure 80: Battery end-use level supply curves.

Table 32 below provides the cost competitive quantity of DR from industrial batteries for each of the service types. Shift, Shimmy load following and Shimmy Regulation are the cost competitive DR service resources for industrial batteries which can provide 2 to 3 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, ADR enabled batteries can provide 1-3 MW per year of cost competitive Shimmy load following and regulation service to the grid. The costs for load following services is $35/kW-yr and between $57-$62/kW-yr for Shimmy regulation services.

Table 32: Quantity of cost competitive Industrial Batteries DR by MW-yr for Shimmy and MWh-yr for Shift.

Industrial Batteries: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	-	2	1	2
50th Percentile Quantity	-	2	1	3
75th Percentile Quantity	-	2	1	3

Table 33 below indicates the cost competitive quantity of DR from residential batteries for each of the service types. Shift and Shimmy regulation are the only DR service resources that are cost competitive and can provide 38 to 54 MWh-yr of Shift service with cost ranging from $28-$30 per kWh-yr, ADR enabled battery technologies can provide 7-11 MW-year of cost competitive Shimmy regulation service to the grid. The costs for regulation services is $57-$62/kW-yr. There is no cost competitive Shed or Shimmy load following resources available from residential batteries.

Table 33: Quantity of cost competitive Residential Batteries DR by MW-yr for Shimmy and MWh-yr for Shift.

Residential Batteries: Quantity of Cost-Competitive DR	Shed	Shift	Shimmy Load-Following	Shimmy Regulation
Quantity of DR (Unit)	MW-yr	MWh-yr	MW-yr	MW-yr
25th Percentile Quantity	-	38	-	7
50th Percentile Quantity	-	46	-	9
75th Percentile Quantity	-	54	-	11

Electric Vehicles

Electric vehicles are critical for addressing the challenge of avoiding climate change (Williams et al 2012) and a significant roll-out of EV in the near future would be consistent with California's recent policy directions on addressing Greenhouse Gas pollution. EVs are a new load category with significant technology potential to provide DR, and early pilots have shown the feasibility of using EV for Regulation[38] .

A pilot project for Shifting EV charging was run in San Diego[39] that included an experimental rate that applied only to sub-metered EV charging. The results were significant and dramatic, with customer EV loads essentially all shifted into the late evening after midnight when prices were low for the experimental rate. The participants in the study controlled the shifts with the built-in charging timer functions on their at-home chargers, set to start charging at the time when the price changed in the TOU tariff. It led to a large EV charging peak between midnight and 5 AM. While the particular timing of the Shift in the study does not match all of the needs we identified for electricity system operation in the future, it indicates the potential for using simple EV charging features to enable DR response to a price.

In order to use EV as a Shift resource, the optimal pattern will sometimes include nighttime charging, but nearly always will include significant Shifts into the middle of the day, between 9 AM - 4PM with reductions in the early evening (see Figure 81). Sometimes the Shifts to late night usage (like the pilot described above) are also optimal. This highlights the value of

[38] See Los Angeles Air Force Base Vehicle to Grid Pilot Project; https://drrc.lbl.gov/sites/all/files/lbnl-6154e.pdf, Marnay, Chris, et al. 2013.
[39]See Final Evaluation for San Diego Gas & Electric's Plug- in Electric Vehicle TOU Pricing and Technology Study, Cook, Ph.D., Jonathan, et al. Nexant, 2014. https://www.sdge.com/sites/default/files/documents/1681437983/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf.

charging infrastructure, since while some Shift is possible with at-home charging scheduling, it would be important to have significant charging infrastructure available to enable daytime charging as well. Commercial charging stations, workplace parking lot charging, and public stations could be important near-term technology deployments to support a flexible EV fleet that can match the needs and capabilities of the next-generation grid.

This example of EV Shifting to daytime charging is an opportunity to show how the analytic framework we developed can also be useful for testing back-of-the-envelope analysis on the effective cost of Shifted energy. We considered the case of installing EV charging at a workplace parking lot, where a commuter's EV may be parked for 6-8 hours or more. A basic analysis is in Table 34 below and shows that the cost of achieving energy Shift with daytime charging infrastructure may be in the range of $30 /kWh, competitive with many categories and consistent with the range of grid-scale value from shift ($20-50 /kWh).

We used a basic EV availability model in our current implementation of DR-PATH, and the dynamics of Shifting charging from at-home to at-work are not captured explicitly in our model, but implicitly through assumptions that enable "home" charging to be flexible and Shift into the day (for example, see the detailed supply curves for Residential battery-electric vehicles in Figure 81 below). The left-side shows a set of Shed and Shimmy plots, and the right-side plot is for Shift. The median supply curve is shown (out of all the possibilities we simulated), along with the 10th and 90th percentile. The basis scenario is the "medium" DR case, in 2025, with 1-in-2 weather, mid-AAEE efficiency trajectory, and Rate Mix #3. EVs could be a significant Shed resource as well, particularly for locally-focused sheds that may not line up with the system-level Shift profiles.

Better understanding the potential of EVs both in terms of climate mitigation from transportation and DR potential is an area where additional research and linking with EV simulation models could help refine our estimates. There are fast changes in the capabilities and use-cases for EVs and uncertainty in the forecast for adoption—because this is a new load category these same uncertainty elements inform planning for renewable generation planning, the distribution system, and other interlocked planning processes. The prospect of autonomous fleets of electric transportation in the future could also be a significant and qualitative re-structuring of the transportation sector, which would have implications for the planning and operation of the power grid as well. This all suggests that continued work across several policy areas (electricity resource planning, system planning, transportation policy, local permitting, etc.) is needed to understand and capture the opportunities from electrification of transportation.

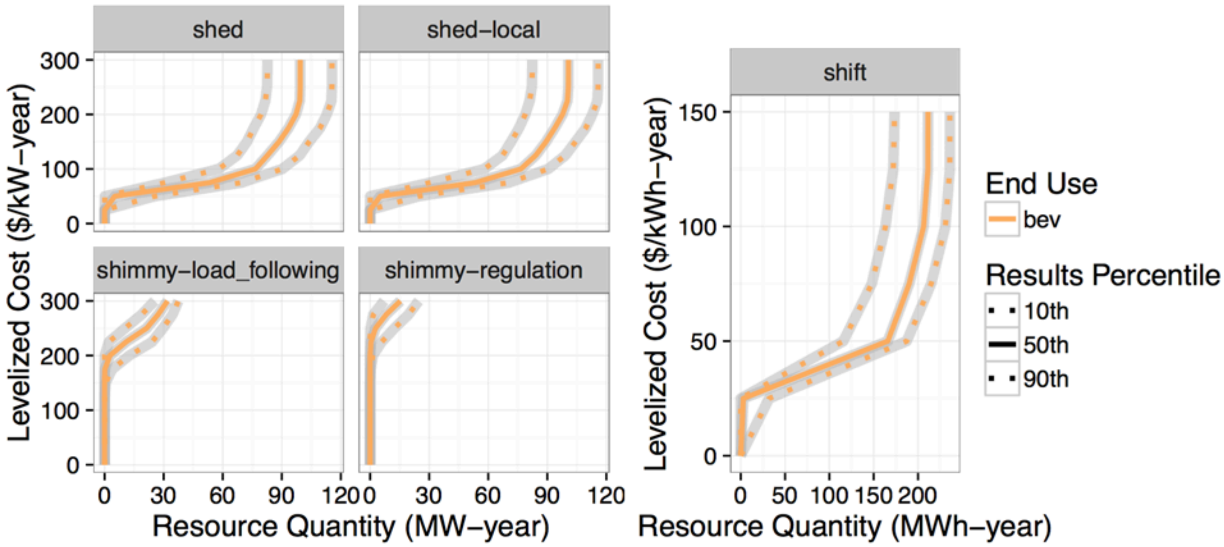

Figure 81: Residential Battery-electric Vehicles (BEV) end-use level supply curves.

Table 34: Levelized costs for Electric Vehicle Shift DR by kWh-yr

Electric Vehicle End-Use: Cost-Competitive Levelized Costs for Shift DR (all sectors)	BEV	PHEV	BEV-Work
Levelized Price per unit of DR	kWh-yr	kWh-yr	kW-yr
25th Percentile Quantity	$28	$28	$28
50th Percentile Quantity	$29	$29	$29
75th Percentile Quantity	$30	$30	$30

Table 35 below indicates the cost competitive quantity of DR from residential electric vehicles for the Shift service type. Residential electric vehicles can provide DR service ranging from 30 to 38 MWh/year from BEVs and 59-83 MWh/year from PHEVs. For commercial EVs, in Table 36, available Shift DR resources include 7-8 MWh/year for BEVs, 2-3 MWh/year for PHEVs and an additional 3 MWh/year for BEV charging at work. EV Shift service is cost competitive with prices ranging from $28-$30 per kWh-yr. These estimates are relatively low, but we expect this is a load category where significant technology innovation and opportunities for dynamic price could introduce lower-cost pathways to flexibility than what is modeled.

Table 35: Quantity of cost competitive Residential EV Shift DR by MWh-yr

Residential EVs: Quantity of Cost-Competitive DR	BEV	PHEV
Quantity of DR (Unit)	MWh-yr	MWh-yr
25th Percentile Quantity	30	59
50th Percentile Quantity	34	71
75th Percentile Quantity	38	83

Table 36: Quantity of cost competitive Commercial EV Shift DR by MWh-yr

Commercial EVs: Quantity of Cost-Competitive DR	BEV	PHEV	BEV-Work
Quantity of DR (Unit)	MWh-yr	MWh-yr	MW-yr
25th Percentile Quantity	7	2	3
50th Percentile Quantity	8	2	3
75th Percentile Quantity	8	3	3

7.2. Energy Analysis with Shed, Shift and Shimmy

The model we developed for this report runs with complex inputs and large datasets, requiring significant computing resources. There is, however, an underlying simplicity to the way we defined the framework for Shed, Shift, and Shimmy that enables quick and first-order analysis of the potential with a few key assumptions. We describe these in brief in this section, and refer technical readers who are interested in the details to the appendices and other supporting material for this study.

Using back-of-the envelope (or spreadsheet-based) estimates of some potential future technology or advance in DR deployment, compared to the results to the prices and quantity of competing resources, could be important tools to help stakeholders engage in the regulatory process, act as a coarse filter for technology R&D targets, and provides insight into the model.

For Shed DR, a first order estimate of the resource quantity for any resource is simply the expected value (average) of the load during the top hours of the year (in the near future, the 5-9 PM period) times the fraction of that load that can be shed by the control technology. The costs depend on the control technology.

For Shift DR, a first order estimate is based on the expected quantity of kWh that are shifted on the average day. An example for EV infrastructure is presented in the text box below.

For Shimmy DR, the simplest way to define a first-order estimate is based on multiplying the average load by a fraction that represents the symmetric availability to turn up/down on either the 5-minute (load following) or 4-second (regulation) timescale.

Back of the Envelope Analysis of Shift from Commercial EV Charging

This example shows how a first-order analysis can be used to estimate the effective cost for DR from a possible technology system. This case is one for Shift, but similar approaches could be taken for Shed and Shimmy resources.

Example: What is the effective cost of Shifted Energy from installing level 2 commercial EV charging stations, based on an expected use pattern and implicit Shifts away from evening charging? The example shown here is illustrative and not meant to be an authoritative result. It suggests an approach for making basic screening assessments of technology.

Step 1: Estimate the all-in average annual cost.

Assume the installation cost per charging point is $5,000, each lasts 10 years, and the operating cost is $200 / year in skilled labor for maintenance. Below we use a financing rate at 7%, which results in a capital recovery factor of 0.14 over the 10-year lifetime.

The annual average cost including financing is thus $5000 x 0.14 + $200 = $900

If the charging point were part of a specifically administered DR program or were incorporated into the ISO market or distribution system operations, additional costs would accrue as well.

Step 2: Estimate the total resource available, matching the characteristics of the DR Type.

Shift DR requires shifting energy from the evening to the daytime, nearly every day of the year. In this example we assume that on an average day the commercial charging station is used during the 8 critical mid-day hours at a capacity factor of 30% (compared to a 6 kW peak charging rate) -- resulting in 14.4 kWh used in daytime hours. Furthermore, we assume that each kWh offsets a kWh that would have otherwise been consumed in the evening.

Step 3: Estimate the effective cost of Shift.

At an annual cost of $770, and a typical daily energy shift of 14.4 kWh, the effective levelized cost of the Shift is $63 /kWh. The expected levelized value of Shift to the grid in 2025 includes the range from $20-50, and there are additional value streams from charging related to the convenience that could lower the effective cost of the Shift resource similar to our treatment of "co-benefits" in the study. This implies that if the assumptions about the cost and usage dynamics we use in this example apply, the value from facilitating energy shifts could defray half of the cost of charging infrastructure.

This back of the envelope demonstrates how new technology can be vetted on first order compared to the framework for Shift DR and suggests that the renewables integration value of daytime-use EV charging infrastructure investment deserves a careful analysis, beyond the treatment in this study.

7.3. Policy considerations

7.3.1. Percieved Market Participation Risk

Survey participants identified that there is great uncertainty on the value for providing DR in the real time market. Questions they posed included:

- What are the potential additional revenues from fast DR enabling technologies?
- How many participants will be in this market?

Stakeholders perceive a risk for investing in fast DR technologies that have poorly defined markets for DR participation and compensation in CAISO.

Market education: technology and energy service providers could benefit by knowing more about the financial benefit of providing DR in real time and day of markets. Survey participants stated that knowing how much money could be available in real time markets and how often resources would be dispatched could drive market adoption. Stakeholders identified the complexity of the CAISO market as a process barrier for evaluating the business case for investment in fast DR technologies in the California markets.

Another form of market participation risk is related to shifting policy landscapes. If the rules and protocols for DR in organized markets and regulatory environments are unstable or poorly implemented, it can lead to aversion to invest in long-term R&D and deployment. As DR expands to provide new service beyond Shed, the predictability and incentives presented to actors in the market will help define the risk associated with third-party and utility investment in market development.

7.3.2. Developing Third Party Markets

Policies that can address the barriers to market entrance to wholesale markets include education on the CAISO markets, standardization of telemetry requirements, easing of dispatch and communication constraints for non-generator resources, and standardized rules for aggregation of DR resources that seek to participate in wholesale markets. The process for integration of aggregated Distributed Energy Resources (DERs) (such as batteries and DR technologies) into the wholesale market and grid could be simplified. The rules and requirements for participation are complex and not well understood by potential market participants, including 3rd parties. Additionally, retail customers do not have ease of access for participation in wholesale power markets nor do they receive compensation for services provided to distribution systems.

7.4. Model Sensitivity and Key Drivers for Potential

We included scenarios and cases in the modeling framework that let us explore the sensitivity of

DR potential to a range of potential futures. The figures and narrative in the sections below express the sensitivity of the model results across key dimensions we included. Each figure shows a baseline quantity for 2025 DR Potential and expresses a range in potential based on sensitivity for the following:

- **DR Market Scenario:** The pace of technology cost and performance improvements.
  - Baseline: Medium scenario.
  - Upper: High scenario
  - Lower: Low Scenario
- **Level of Portfolio Benefits:** A measure of business model integration, defined by the ability of DR aggregators and/or utility programs to capture revenue from a range of services enabled by DR technology.
  - Baseline: Costs are net ISO revenue and site-level co-benefits.
  - Upper: Also includes revenue from hypothetical distribution system service.
  - Lower: Only including ISO revenue, without site-level co-benefits.
- **Monte Carlo Analysis:** The result of uncertainty analysis we conducted on the future cost and performance of DR technology. The range shown (from 25th to 75th percentile) is analogous to the range of the box plots in Figure 3 and other similar figures.
  - Baseline: 50th Percentile outcome from analysis
  - Upper: 75th Percentile outcome from analysis
  - Lower: 25th Percentile outcome from analysis
- **Weather, EE Scenario, and Rate Mix:** We simulated many combinations of weather (1-in-2 vs. 1-in-10), Energy Efficiency trajectory (without "additional achievable energy efficiency", AAEE, and with a "mid" level of AAEE), and different mixes of retail rates (Rate Mixes 1, 2, and 3).
  - Baseline: The average of all combinations
  - Upper: The maximum of the combined options
  - Lower: The minimum of the combined options
- **Renewable Integration Status:** We included two different "bookend" cases in the RESOLVE model to estimate system-level value from demand response, one with "high" levels of renewable curtailment and the other with "low" curtailment due to other renewable integration activities (transmission expansion, regional coordination, etc.).
  - Baseline: High Curtailment
  - Lower: Low Curtailment

Shift Sensitivity:

The DR market and technology scenario is the strongest influence on the cost-effective quantity of Shift DR (with a ~40% difference between the "medium" and "high" scenario), closely followed by the level of renewables integration and the ability of DR businesses to access a

portfolio of value streams with their investments. There is little sensitivity related to the uncertainty in technology cost and performance inputs or the weather, retail rates and EE trajectories we included (Figure 82; Note: The baseline is defined for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label). The strong influence of renewables integration is expected for Shift since the original source of value for the resource is from exactly that kind of service (capturing more renewable energy, avoiding curtailment).

The sensitivity of Shift to DR scenario is emblematic of the structure of the model; because the scenarios include both cost and performance dimensions there are interactive effects on the unit costs (which divide cost by quantity). These effects tend to amplify the combined change in performance and cost. For example, in a case where the cost of technology is reduced by 25% and the performance is increased by 25%, the net effect is that there is 25% more resource available at a unit cost that is reduced by 40% compared to the base case.

Our results suggest that a focus on technology development and cost reduction (i.e., pushing towards a "high" DR scenario) could have significant influence on the availability of Shift resources, along with enabling Shift resources to also serve the distribution system. There are interactive tradeoffs between decentralized renewables integration like Shift and system-level investments like centralized storage and transmission infrastructure. The reduction in Shift cost effectiveness when there are other renewables integration solutions employed suggests that Shift (and DR in general) should be considered part of an integrated set of solutions.

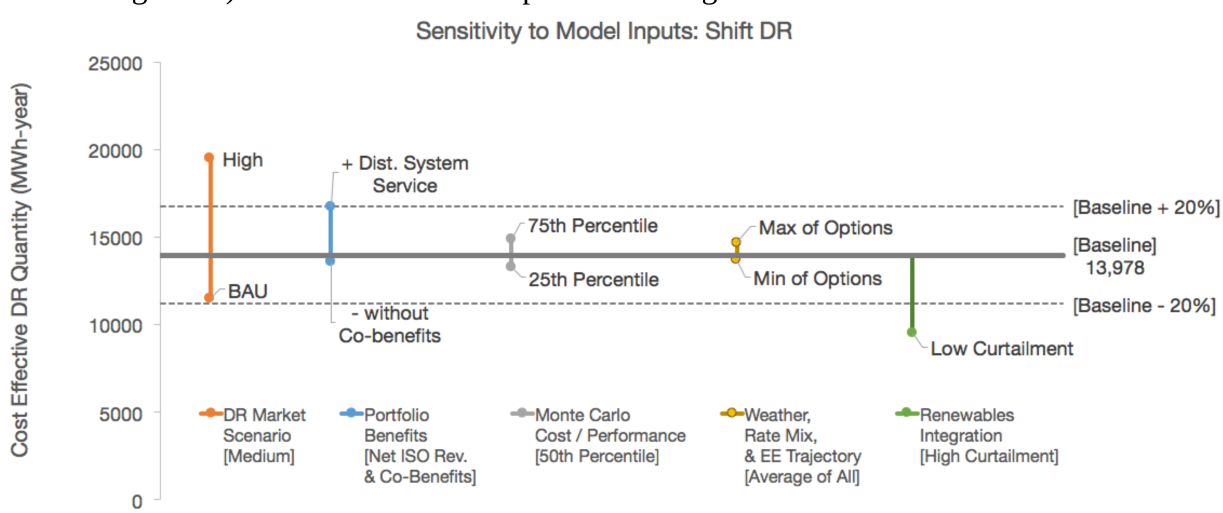

Figure 82: Sensitivity analysis for Shift DR.

Shimmy Sensitivity:

For Shimmy DR (both load following (Figure 83) and regulation (Figure 84)) the strongest influence on potential is the ability to build portfolio benefits and access site-level co-benefits and distribution system service revenue (Note: The baselines in both figures below are defined

for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label). There are also strong effects from the DR market and technology scenario. Similar to Shift DR, there is little effect from the weather, retail rates, and EE trajectories we simulated. The range of outcomes from our Monte Carlo uncertainty analysis were within the +/- 20% bounds around the baseline we show on the figures as well.

Renewables integration has a significant influence on the cost effective quantity of Shimmy DR. In a low-curtailment scenario where there are other options, the value of Shimmy is reduced and the cost-effective quantity drops from near 300 MW to 60 MW for load following and 200 MW for regulation.

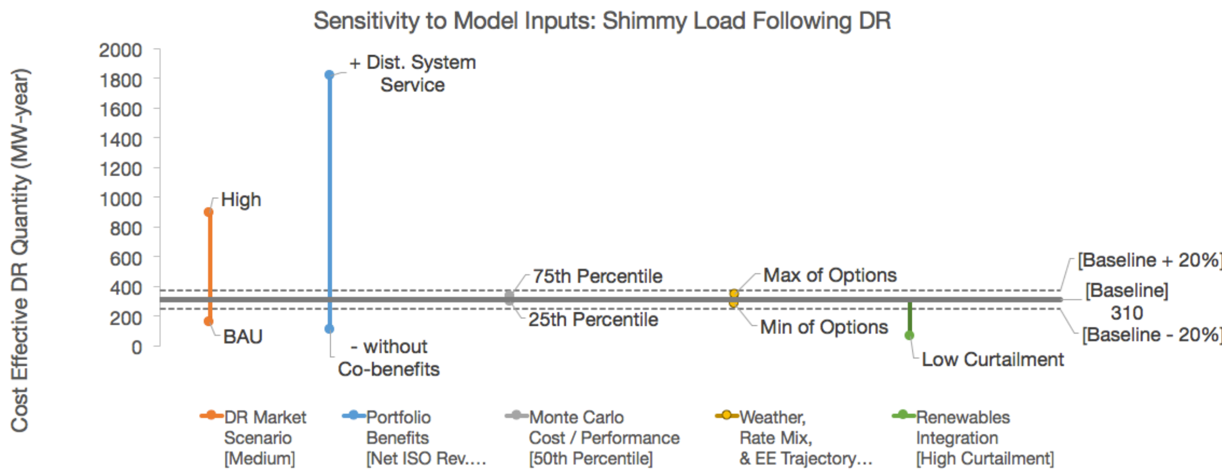

Figure 83: Sensitivity analysis for Shimmy Load Following DR.

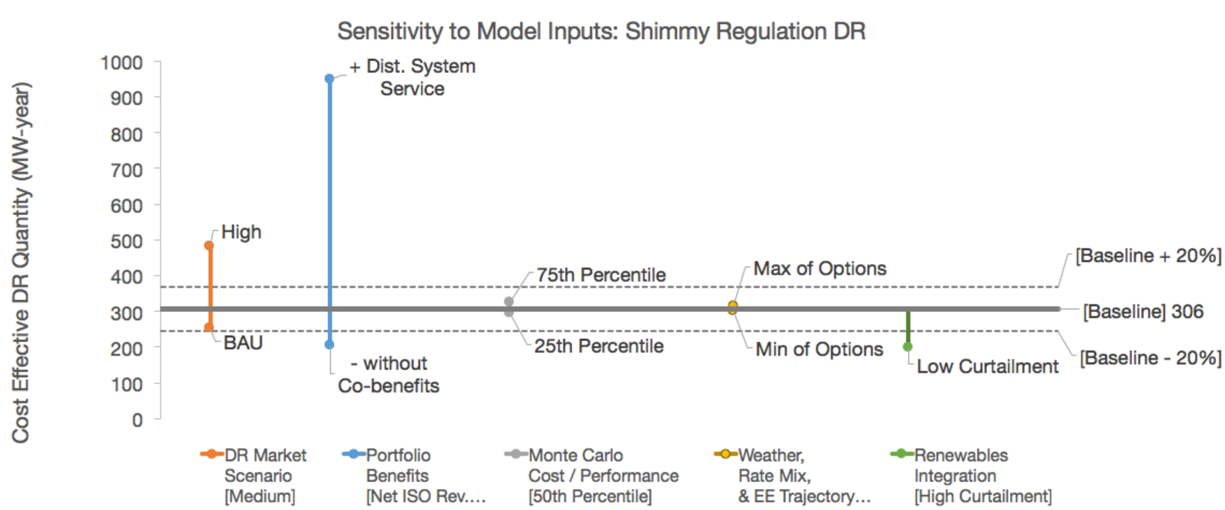

Figure 84 Sensitivity analysis for Shimmy Regulation DR.

Shed Sensitivity

We show two metrics for Shed sensitivity—one for system-level Shed (Figure 85) and the other for "local" Shed, that is, Shed resources that can respond in less than 20 minutes and are located in a current capacity constrained local area. The baseline is defined for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label. The baseline for system-level shed is low – only about 400 MW – because the resource costs are being compared to a very low system-level value for Shed (as we describe above, there is sufficient capacity for carrying the system peak through our study period, and thus no generation capacity investment deferment opportunities). It is notable that if Shed resources are focused on serving the distribution system, there could be substantial usefulness across the system, targeted on feeders where there is a need (and an opportunity to defer investment in distribution infrastructure to manage the local loads and generation).

The local Shed results (Figure 86) paint a different picture, with a baseline cost-effective resource availability on the order of 5 GW-year. The baseline is defined for 2025, with the baseline scenario setting indicated in square brackets on each sensitivity category label. Unlike the other plots in this section, in this case the cost-effective DR quantity is determined by a price referent instead of simulated system-level value. This is based on resources valued at $200/kW-year and in place of the sensitivity to renewables integration we show how the cost effective quantity changes based on a change in price referent, with $100 /kW-year and $300 /kW-year as benchmark values. There is 3x the gap from $100-200 compared to $200-300 because at $300/kW-year nearly every available resource is cost effective (saturation in supply). The specific avoided cost is the strongest influencing factor on the cost-effective quantity of local Shed and would depend on the details of a local area. For local Shed, the influence of DR technology and market progress is strong as well (manifested in sensitivity to the DR scenario).

Taken together these Shed sensitivity results provide support to the concept of refocusing Shed DR in targeted areas – local capacity constrained areas and on the distribution system.

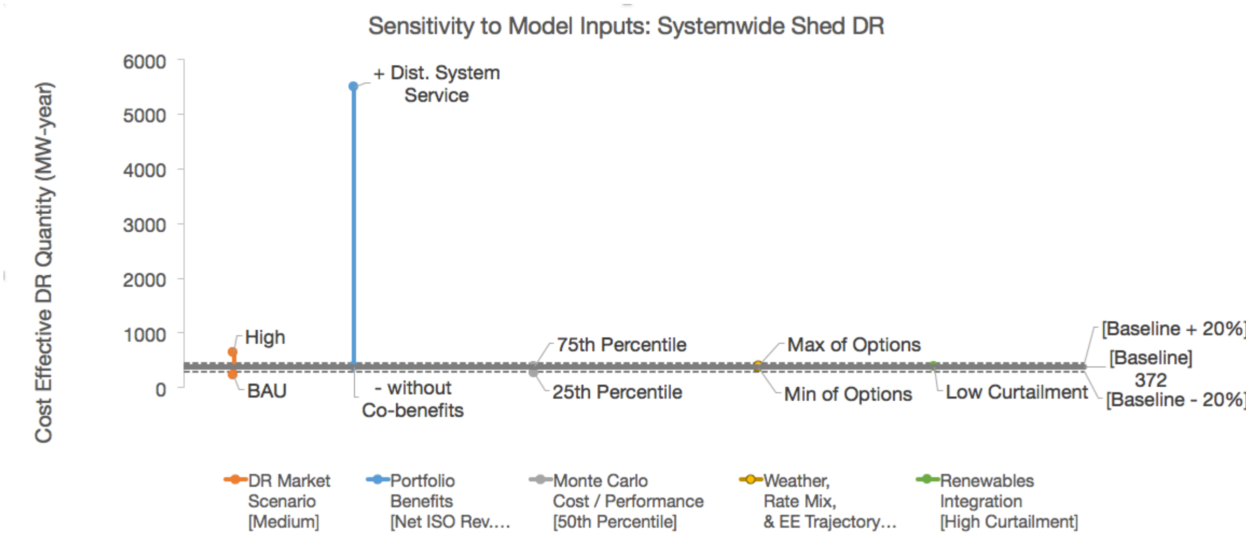

Figure 85: Sensitivity analysis for Systemwide Shed DR.

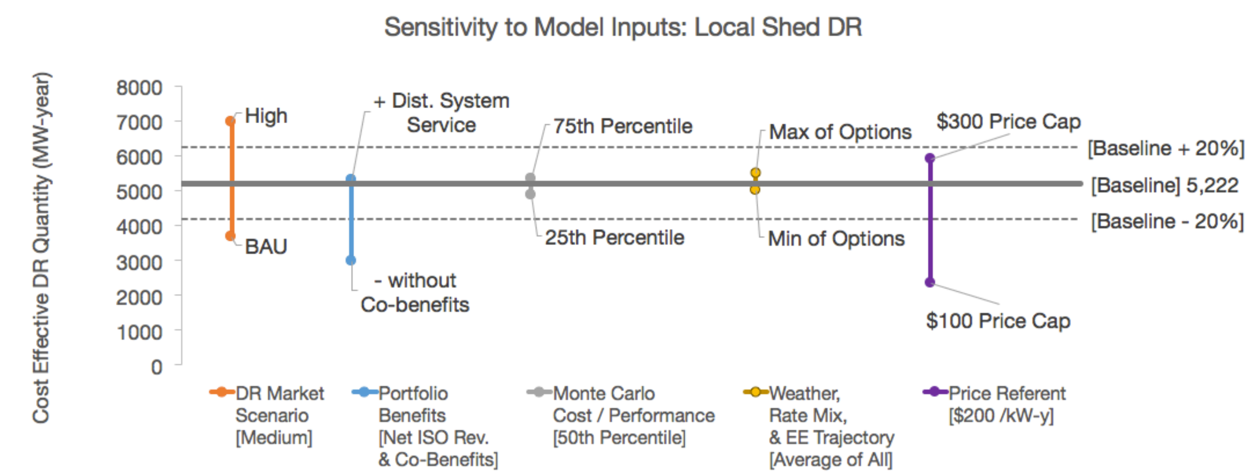

Figure 86: Sensitivity analysis for Local Shed DR.

8. Achieving DR Potential: Evolving Policy Context for DR

Ultimately the scale of DR potential in California will depend on how the policy environment, market design, and technology research and development progress over the coming years. Below we describe the context of the emerging next-generation grid DR landscape:

8.1. Importance of market design

The CAISO and the CPUC are undergoing a parallel set of reforms to create space in the energy and ancillary services market for distributed resources and DR. As these processes of market definition continue, important design decisions are being made that will influence the ability of and incentives for demand response to participate. Stakeholders we heard from raised issues about a range of market design choices that bear directly on the potential for DR (and are core to defining it). Telemetry requirements can have significant influence on the cost of fast DR, requirements for continuously variable dispatch present challenges to some DR-ready processes that run as a continuous batch, and there are constraints in the capabilities of advanced metering infrastructure to support settlement of fast resources.

Controllable DR resources, including behind the meter battery storage, can provide flexible services to existing wholesale markets that can potentially defer the need for additional conventional generation resources, with sufficient penetration. Controllable DR resources can support the integration of renewable energy sources, and support policy targets for renewable standards and a low carbon future. CAISO and the CPUC continue to develop rules that encourage broader participation of non-generator resources in the wholesale markets, including load following ancillary services.

8.2. Energy Efficiency, Load-Modifying DR and Supply DR

There is an ongoing discussion around interactive effects of energy efficiency and demand response, and the bifurcation of DR into load-modifying and supply resources facilitates a new way of viewing these effects. One could broadly consider energy efficiency (EE) as a load-modifying DR measure, whereby the net load is decreased by an efficiency investment (and the timing of service remains unchanged). Thus EE investments in general have “load-modifying” DR effects, reducing the need to procure peak capacity because the peak load is reduced. Depending on the load types that are upgraded or improved, it is possible as well that less

flexible ramping capacity and other advanced grid products will be required due to energy efficiency.

On the other hand, improved efficiency for an end use that also participates as supply DR reduces the availability of baseline load to actively shed. It is an important point, however, that the net sum of the DR resource is unchanged in general, and could be increased through EE investment. Consider an example of an HVAC load that is 10 kW baseline and can be reduced by half of the service level (5 kW) with dispatchable control as supply DR. If the load is efficiency upgraded with one that uses 75 percent of the original energy load (i.e., an EE benefit of 25 percent), the baseline is now 7.5 kW for the same baseline level of service. If the service level is still reduced to half during a DR event, this means that there is only 3.75 kW available for supply DR (less than the original 5 kW shed), but the overall effect of the combined EE and DR on the net load is a reduction of 6.25 kW—an increase in total DR compared to the original configuration that also comes with all the benefits of EE upgrades. If one only considers the availability of supply DR in the absence of the underlying load-modifying effects, however, an efficiency investment can appear to reduce the quantity of available demand response.

Energy-efficiency upgrades often present opportunities for cost-effective controls upgrades (either as part of an integrated project or as controls built into new equipment in an Internet-of-things approach) that can reduce the cost of enabling DR. An instructive example is the case of energy-efficient lighting. Light-emitting diode (LED) lighting is now an established market segment and is rapidly improving in efficiency, recently surpassing the incumbent fluorescent technologies prevalent for the last few decades. The efficiency benefits of LED lighting are often large, reducing the theoretical quantity of dispatchable DR available from the load, but the upgrade is an opportunity to simultaneously make the lighting stock more controllable for both occupant service and demand response. The markets for distributed energy technologies that provide multi-attribute services like these are still evolving, and often there are challenges to ensure the services are appropriately valued. The DR market for lighting is still in its infancy, and growth will depend on numerous market transformation activities occurring simultaneously: building product availability, lowering technology cost, increasing reliability, improving market knowledge (i.e., designers, specifiers, contractors, building owners/occupants, building officials, and facility managers all becoming conversant in the technology), and aligning capital investment support.

Solutions for addressing the DR lighting in particular are the subject of a recent California Energy Commission Electric Program Investment Charge (EPIC) PON 15-311 solicitation, and LBNL's awarded contract, to develop "The Value Proposition for Cost-Effective, DR-Enabling, Nonresidential Lighting System Retrofits in California Buildings." This project will explore energy and non-energy benefits in California for DR-enabling, advanced lighting control systems leading to a more comprehensive and accurate financial analysis for the technology. The goal is to support enhancement of California's Title 24 and integrated demand-side

management program offerings, to accelerate market adoption for the technology. Targeted market transformation efforts like these are critical for technology areas with significant overlap between traditionally separate value areas like EE and DR.

The overall effect of EE and DR integration could be an overall increase in combined load-modifying and supply DR availability for meeting system capacity needs, with supply DR at a lower cost compared to DR-only technology investments. Achieving this synergy will however require significant effort to align policy and market frameworks.

8.3. DR Targets and the Importance of Baselines

There is a significant need for careful integration between CPUC and CAISO policies to ensure that the market designs and real-world integration are matched well with the most cost-effective pathways for DR service. A critical awareness of how baselines are set for participating load in ISO markets is needed. With “every day” DR like Shift it is particularly challenging to accurately measure and compensate load-based resources in the same framework as conventional generation. Price response is a viable and potentially useful tool, particularly if individual DR-enabled loads with low-cost submetering can be subject to a special rate schedule (e.g., EV charging rates with sub-metered chargers).

The challenges of measuring the counterfactual baseline for DR is well documented, and the way DR is measured and accounted for in the market will strongly influence the competitiveness of DR and the ability of market participants to provide resources that meet policy targets for resource adequacy and other applications. The DR we include in our modeling effort inherently has a known counterfactual expected baseline—this is the load profile that is the basis for the expected DR resource. If operational practice fails to accurately measure the load impact of DR, the apparent resource could deviate from its actual value or become obscured by noise in the measurement.

There are also similar baseline issues at play for considering policy targets for DR. In many cases policy is set in terms of minimum thresholds for procurements that are a fraction of total procurement or an absolute minimum. In addition to bias or imprecision that is introduced from operational measurement and verification, which would affect any kind of policy compliance, the magnitude of DR resources also depends on exogenous effects of weather (as shown in the comparison between weather cases for our model) and economic cycles (not shown in the model). During the recent recession there was a decrease in DR related to slowed economic activity. This slower activity can result in lower industrial electric loads and lower rates of energy use in office and retail buildings.

9. Opportunities for Breakthrough in Technology and Markets

9.1. Building Codes

The California Energy Commission has developed requirements to install DR automation technology as part of Title 24. These requirements' success could greatly reduce the new DR systems' first cost. Not only can the Title 24 requirements reduce the cost for automated DR in new buildings, they could also help to disseminate key information to control companies about the commitment to formal communication standards for DR automation. For large building control systems, the DR automation cost could be extremely low if the DR automation was available in conventional building automation system controls. The majority of large commercial and industrial DR is installed with gateway boxes. Unfortunately, there is great confusion about the current DR requirements in Title 24, and the code officials and key market players have received little to no education on the intent of these DR requirements. Similarly, control companies and design engineers have expressed concerns about the lack of consistency in interpreting the code requirements. Careful attention to this issue is needed to address the market confusion generated by inclusion of this DR requirement in Title 24. The CPUC and the IOUs can help address this problem by evaluating the knowledge gaps that exist around the DR code issues and develop training and information to address these gaps. Given the language in Title 24 on DR automation, there are opportunities to ensure that retrofits and new buildings that require code compliance are provided with clear information about the DR programs for which the building may be eligible.

9.2. Internet of Things (IoT)

California is fortunate to be the home of many established and emerging companies and industries taking advantage of the incredible opportunities for using the Internet in new ways. One of the most promising areas for DR is the capability of new packages of technologies to control, measure, and automate demand response. A recent study by Lanzisera et al. (2015) showed that new DR technology platforms could be capable of providing fast load shed for between $20 and $300 per kW of available load. The study noted:

> "Many new technologies will be installed for energy efficiency or non-energy benefits (e.g., improved lighting quality or controllability), and the ability to use them for fast DR is a secondary benefit. Therefore, the cost of enabling them for DR may approach zero if a software-only solution can be deployed to enable fast DR after devices are installed for other reasons."

Some of the lowest-cost DR technologies are new communicating thermostats that are installed by the customer for energy management and convenience, but these can also qualify for automated DR programs because they support open automated demand response (OpenADR).

9.3. Integrated DSM (IDSM) and Locational Targeting

In recent years, the utilities' EE and DR goals have been planned, managed and evaluated separately from each other. Customers are approached separately for EE and DR programs, which produces customer confusion. The customer engagement activities will be more cost-effective if the technology costs for EE and DR technologies are integrated. For example, at the Sacramento Municipal Utility District (SMUD), when new building HVAC automation or lighting controls are incentivized with energy efficiency DSM funds, they require the technology system to support OpenADR, so it will be less expensive for the building to join a DR program in the future. This integration creates a "future-proofed" DR-enabling technology platform when implementing EE project investments. There is a need to better link EE and DR measures so that they are more cost-effective when bundled. To achieve this will require some creative new measurement and verification methods to value both the EE and the DR performance of an IDSM measure.

Furthermore, the visibility into the distribution system and bulk power operations is only growing. As techniques emerge for geographically targeted information on needs, an integrated mix of DR, EE, onsite generation, and storage could provide significant value to the customer and local operations.

9.4. Customer Feedback and Behavior Based Programs

Recent research (Cappers and Sneer 2014; Todd et al. 2014) has found that utilities and aggregators that focus program efforts on customer feedback, engagement, and behavior have successfully encouraged DR participation and energy conservation during peak hours. Residential in-home displays and monthly "home energy reports" have been shown to help raise awareness of energy use and provide some conservation effects. Similarly, in large commercial and industrial (C&I) programs, aggregators have experience providing custom feedback to C&I customers on their DR strategies' performance. This feedback occurs quickly after DR events and helps to provide direct information about the customer's electric load shape and the economic incentives. This customer feedback stands in sharp contrast to the IOU program feedback.

9.5. DR Aggregators' Role

California needs to continue to explore how to partner optimally with aggregators to expand the

capabilities of responsive load in the state. A competitive, multi-party market for DR services would help drive innovation in technology and business models for delivering flexibility from loads and DER broadly. To support this market and drive it towards ratepayer interests, the firms should face incentives and revenue opportunities that are related to the full value provided to the grid by DER. The current market setup discourages collaborative support for resources between parties. For aggregators to target the highest-value sites, there is a need for ongoing and cyber-secure methods of focusing investments based on customer characteristics and the context of the distribution feeder and location on the system.

Efforts like the DRAM and other innovative procurement mechanisms, along with newly available data from the Distributed Resources Plan proceeding could help clarify the potential opportunities for aggregated resources to serve system and local needs.

10. Recommendations for Guiding California's DR Pathways

Our study presents a new framework for assessing the needs of the grid and potential of DR to support significant shifts in the generation mix and architecture of the system. In the course of building the modeling framework and analyzing the results we identify a range of needs for to inform the business community, policymakers, and technology developers who are active in the space.

10.1. Policy Direction

Data-driven Energy Markets and Policy

This study represents a new framework for approaching demand-side energy analysis in support of public policy for demand response. With a foundation of large AMI data samples, we show how a bottom-up, hourly-resolution electricity system model can provide important insight into demand-side resource potential coincident with weather and renewable generation. We worked with the CPUC to make both available in an open source format the input datasets, with protection against customer privacy, and the supply curve model. Using transparent models and up-to-date data not only improves the results of the study by providing many more avenues for feedback but could also, over time, enable stakeholders to engage in the regulatory process with better quantitative capabilities.

In order to catalyze spin-off work, alternative scenarios, technology R&D and market intelligence, we recommend implementing a demand-side, electric load data release at high spatial and temporal resolution that is: 1) publicly available; 2) predictably distributed; and 3) uniformly-formatted.

Additional work will be needed as well focused on data access for third-party implementers, streamlining the settlement and telemetry with CAISO, integrating transmission-level and distribution system operations, and other information technology challenges. With an underlying foundation of data about distributed energy systems' operation that reveals California's electricity users' and investment opportunities' diversity, the public and private sector can build the knowledge to chart a cost-effective and high performance DR technology future.

Catalyze Shift

Shifting energy demand from early morning and evening hours to the middle of the day is a robust strategy for supporting renewables integration, and it creates significant value to ratepayers by making it less expensive to meet RPS targets. We identified that this DR category could be achieved through either a market-integration or prices pathway, and that further research on an accelerated timeline is needed to understand the best approach. A key difference between conventional load-shed DR and shift we identified as valuable is the operational strategy: Shift involves day-to-day and frequent (or permanent) changes in the patterns of load

with a depth appropriate to maintain satisfactory energy service, instead of infrequent and deep sheds. There is significant work needed to understand the ability of current DR sites to achieve shifts, and identify new application areas that match the resource.

Different sectors and applications may lend themselves to different Shift flexibility pathways as well – highly automated processes may be able to subtly shift based on day-ahead dynamic price forecasts while behavioral and structural changes are driven by longer-run prices. Layering long-term shifts with automated dispatchability for shorter-term could provide low-cost portfolios.

The core challenge for appropriately driving shifts is balancing overall CAISO-level system requirements with local distribution-level IOU requirements with, in turn, local facility/DER requirements. Different market structures, business models and rates/tariff designs can be reflected in further analyses to better bound and evaluate these parameters to better inform policymakers and key stakeholders regarding the most effective way to invoke Shift resources moving forward into the future.

In our analysis of the Shift resource potential we highlighted the tension between the bifurcation concept and Shift resource potential. There are discussions and working groups at the CAISO underway to create frameworks for exposing shiftable loads to the price in the energy market through a bidirectional bidding and dispatch system, but with significant challenges in measuring baselines for settlement and with additional transactions costs compared to a simple dynamic tariff for those loads. On the other hand, without the organizing principle of the ISO market it could present a challenge to build business models that push enabling technology out to the thousands of sites that would need upgrades to dynamically respond to day-to-day needs.

This is an area where significant additional work is needed to better understand the dynamics of energy Shifting using automated control. Questions to be explored include:

- How much energy Shift is achievable with differentiated pricing at the end-use level? With low-cost sub metering it could be possible to have different devices face different price timescales, providing certainty to users in terms of their directed service but allowing autonomous cycling devices like refrigerators and HVAC to meet finer-scale system needs.
- Early studies on EV’s (a SDG&E pilot) indicate that sub-metered loads with dedicated prices can be effective, but would the results hold for broader applications?
- What is the business case for energy service providers who indicated that “static” time-of-use rates that apply broadly are not likely to achieve significant Shifts?
- How can existing control technology be deployed for energy shifts? What are the gaps in technology that can be filled with pilots and R&D?

We note that there is already work underway to pilot test and develop programs and resources

that shift energy to capture mid-day renewable generation, some of which are listed below. These are important initiatives to expand the knowledge base around Shift broadly, and the results could help inform policy and R&D directions going forward.

- **New TOU price structures:** All three IOU in California have proposed new TOU peak periods that are in the late afternoon / early evening designed to incentivize shifting some of that evening consumption to the middle of the day. This represents an important change, and is notable because for years customers have been told that time-varying prices are designed to move consumption out of the mid-afternoon and into morning and evening hours. The new TOU proposals from the IOU turn this conventional wisdom around, and it is likely that a significant consumer education campaign will be needed to help clarify the new opportunity.
- **Special pricing pilots**: There have been a few targeted pricing pilots that aim to build mid-day demand. One is the "Matinee Pricing" pilot in the context of the Water-Energy Nexus rulemaking[40], which provides periods of low pricing in the middle of the day during key times of year. Two pilots are underway with EV charging; one is a partnership between PG&E and BMW[41] with early indications of high satisfaction among drivers and meaningful shifts of energy in response to the program signals. Another EV pricing pilot run by SDG&E[42] provides day-ahead dynamic pricing at multi-unit dwelling and workplace charging locations, enabling customers to optimize their charging schedule based on information about the expected marginal cost of electricity on the bulk power system and local circuit conditions. More pilots like these, with targeted pricing for particular sectors and end-uses, could help reveal the depth of Shift that is possible with the combination of pricing and automated response.
- **Excess supply initiatives:** Broader work that includes demand response, distributed storage, energy efficiency, and other mechanisms to address "excess supply" were approved for the three IOU in CPUC decision 16-06-029. Each utility proposed unique approaches, including pricing, water pumping control, energy storage, integration of ancillary services with shiftable load, and others.

[40] CPUC Decision 16-11-021

[41] http://www.pgecurrents.com/2016/11/14/pge-bmw-partner-on-next-phase-of-pilot-studying-advanced-electric-vehicle-charging/

[42] CPUC Decision 16-01-045

Fast DR and Shimmy

DR can likely provide significant value to the system for regulating frequency, reducing the impact of short-run deviations and ramps, and meeting contingency needs. This will require technology investment to enable loads, software integration with CAISO markets, and new approaches to engage customers with devices or equipment that can respond. Integration between ISO market practices and supporting policy for fast DR is important for supporting an appropriate scale for DR capabilities in this area.

Benchmark IOU Demand Response Programs

Existing IOU DR programs have traditionally been evaluated for effectiveness on an annual basis. There is a strong need to evaluate the persistence of DR programs, customer engagement, and investments in technologies. Understanding these programs' and technologies' long-term value can help inform investments for the IOUs and policymakers of "what works". One of the DR program challenges is customer attrition and churn, which can have an adverse effect on technology investments and program performance if assets are left stranded. By examining a DR program's effectiveness over a three year period, or longer, policymakers can gather greater insights on whether investments in DR technologies persist. We recommend that there be program evaluation, data collection and a framework to examine the long-term value of DR systems.

Additionally, we recommend that program evaluations be benchmarked to include technology costs, measures of response capabilities across a range of dimensions (not just load shed), and customer profiles. As DR investments evolve beyond conventional peak capacity curtailment programs, a focus on tracking and understanding data-driven investments in DR services could help ensure policy keeps pace with the fast-changing market.

Future Rate Design for Residential and Non-Residential Customers

Over the next decade, future rates in California will play a major role in managing energy consumption patterns. The CPUC has committed to instituting default TOU tariffs for residential customers in 2019, however, those rate structures are undetermined. As this study indicates, there is an opportunity to use electricity rates to encourage customers to shift load from evening hours into the middle of the day. Retail rates should be designed to assist with renewable generation resource integration as a main objective. In the next few years, retail rates for all non-residential and residential customers that include an aggressive off-peak period during mid-day hours that encourages load consumption, should be piloted to determine the appropriate price signals and off-peak-to-peak ratios under a default scenario. Pricing pilots can ensure that rates are designed incorporating elasticity estimates from empirical data.

Our research indicates that using retail rates to promote load shifting may be among the most cost-competitive methods to both reduce renewable curtailment and peak load reduction. We did

not model specific rates or rate structures to determine the best way to accomplish this, and therefore, we advocate for additional rate impact analyses both for individual IOU service territories and at CAISO transmission system levels.

Developing Market Mechanisms for Market Entrance

Third party aggregators and energy service providers have been challenged in recent years to gain access to and participate in energy and capacity wholesale markets. Recently, the Demand Response Auction Mechanism (DRAM) pilots have improved the ability for these third party participants to engage in supply side DR markets. Programs, such as DRAM, should be piloted to encourage a diverse pool of DR resources that can provide services to the transmission system.

10.2. Future Business Models for Energy Service Providers and Utilities

The future of the utility business model and **business models for third party energy service and DR aggregators** have been the subject of much debate and discussion in the past several years (e.g., see Satchwell et al 2015), and we expect this will only amplify going forward as the grid and distribution system conditions evolve, bringing to fruition many of the concepts that up to now have only been hypothetical scenarios for renewable penetration, distributed resources, etc. In our model we do not explicitly account for the nuances of particular business models – instead focusing on what is possible if the technology is available and incentives are aligned to roll it out. Thus it is important here to note the key areas of work that will be needed to achieve business models that can sustainably deliver DR resources, capturing enough revenue to properly incentivize the deployment of DR.

Portfolio Approaches

It is notable that in our sensitivity analysis a significantly large factor for determining DR potential is the ability of resources to access **portfolio** benefits from the technology (ranging from +20% to +1000% and up compared to baseline cases. It is simply much more economically effective if the same widget that provides DR to system or local needs also can provide monetizeable value to the distribution system and/or site-level applications. This suggests that there is a strong incentive to identify business models that span large spatial domains – from the building site to the distribution feeder to the transmission system. In the context of California's bifurcation of demand response (separating the operation of resources for transmission system benefits from other resources) this could be particularly challenging.

Our study considered a range of DR applications, and we constructed portfolio-based resources across spatial domains (e.g., including site-level "behind-the-meter" co-benefits and distribution system benefits for estimating the effective cost of transmission system-level service). These

portfolios are predicated on the assumption that it is possible both technically and from a business model perspective to offer service across scales. Work is needed to understand the technology capabilities to provide multi-scale service and where "co-benefits" and parallel uses of control technology are possible. This should be carefully coupled with a focused effort to understand the necessary business and market conditions to incentivize integrated demand-side energy planning. These discussions and rulemakings are underway and the results of our study points toward significant gains in cost-effective DR potential if the barriers to portfolios of decentralized energy service are overcome. Our sensitivity analysis showed that access to portfolio-based revenue streams is greater than or equal to the differences between our DR technology progress scenarios for capacity-based DR like Shed and Shimmy. Shift exhibits lower sensitivity to both factors (technology and portfolio approaches).

In particular, we identify the need for several linked efforts that help unlock the portfolio-based potential our model suggests could be available:

- Study and pilot test the business case for combined EE and DR offers. The installation of EE upgrades is a critical moment of opportunity to engage customers to participate in DR programs and improve controllability of loads (and vice versa). If EE and DR programs remain in separate silos, the site-level co-benefits we identify would not come to fruition.
- Continue work on locally focused and targeted Sheds in support of the distribution system and local generation capacity constraints. The management and investment planning of the distribution system is a critical element of this. Our study used only notional and randomly assigned value for distribution system DR. In part, the way forward should include more explicit modeling of the opportunity for combining transmission and distribution system service that is spatially resolved in the context of the customers on constrained circuits. A vital outcome, if third party aggregators are going to provide combined service, would be identifying a framework for enabling non-utility actors in the market to have good access to data that helps them understand where specifically the opportunities are to support the distribution system, without compromising customer privacy.
- The core challenge of portfolio-based DR which spans transmission, distribution, and behind-the-meter service is the future of the utility business model. Bifurcation of DR suggests that utilities could take more of a supporting role in enabling aggregators to connect customers with the ISO market, but these aggregators are at a distinct disadvantage when it comes to access to customers and information on the distribution system. What will the utilities' future expectations be for cultivating access to information about customers in their service territory and conditions on the distribution system? Cost effective DR potential increases when market participants can identify and target highest-value sites and enabling technologies, and work towards sharing

information and standardized platforms and protocols for engagement between enterprises will be key to unlocking the potential we identified is technically and economically achievable with the proper support.

- While we explored the upside potential from participation across the transmission, distribution, and behind-the-meter portions of the electricity system, we did not simulate multiple participation in system-level markets, which could change the single-market results and reduce the effective cost of providing DR. It will take a combination of technology pilots, improvements to the modeling framework, and understanding the market and policy implications for multi-objective DR to understand and achieve the additional potential that could be captured with integrated portfolios.

Transition from System to Local Sheds

Our study identified that the "conventional" system-wide peak shed DR is unlikely to provide significant value to the grid in the future, but there are still important uses of the existing and future Shed technology stock for meeting local capacity needs, and these resources could support distribution system operation and planning. Our background research indicated the value on the distribution system is highly concentrated on a small fraction of constrained circuits, highlighting the need for targeting granular, load control investment. Key to unleashing this value is working closely with pertinent stakeholders to clearly identify building local shed resources that evolve over time to provide grid services to a changing system need. In other words, to mitigate future requirements, paths must be identified that avoid investing in DERs that represent 'technological cul-de-sacs' that render sites mal-adapted to future energy systems or foreclose on opportunities for integrated approaches later.

Community Choice Aggregation[43]

Community Choice Aggregation is rapidly expanding in California and it is not implausible that a majority of load in the state could be procured through CCA in the future. Because CCA also set local rates, their role in future retail pricing is a key factor for DR policy design. Thus far CCA rates have closely mirrored the benchmark set of rates offered by the IOU that serves load in the territory, but there is no guarantee this will persist. Because CCA have local boards and are not subject to the same regulatory oversight as IOU, there could be divergent sets of retail rates offered across the regions that reflect the particular goals, incentives and costs for the CCA. Whether this presents challenges for or helps catalyze achieving more effective price response is unknown and subject to the trajectory of CCA in California.

Will CCA be allowed to run DR and DER programs in parallel or on behalf of the IOU as the retail face of electricity consumption? In order for CCA to offer smart pricing programs, support

[43] These draw from "Community Coice Aggregation En Banc Background Paper" CPUC Staff, Feb 1 2017, available at: http://www.cpuc.ca.gov/general.aspx?id=2567

DER integration, and incentivize customer behavior to match a combination of bulk power and distribution system needs, tight integration with the hosting IOU may be needed.

10.3. Technology Development

Shift as Energy DR

A key concept to keep in mind for Shift market and technology development is that it is a resource with an energy-based, cumulative value, rather than a power-based capacity value, placing it in a separate category from conventional Shed DR. Unlike with Shed, where the value of a resource derives strongly from its reliability and usefulness in real-time dispatch, the value of Shift resources come from multi-hour changes and accumulate through the years. As more renewable electricity that would otherwise be curtailed is captured, the value increases.

The first order contours of the ideal Shift profile appear to be relatively simple and predictable (use less in the night and more in the day), suggests that there is a strong potential role for permanent load shifting and rescheduling efforts. In addition, notification with day-ahead price schedules could let loads with day-to-day flexibility optimize operation further. The current stock of conventional DR technology is fast enough to respond to these day-ahead signals, and may present a low-cost alternative to enabling new DR sites.

Shift DR could present high-value, low-cost opportunities because the notification time for system needs is sufficiently long. A technology development agenda for Shift could include:

- Study of how the existing stock of DR control technology could be adapted and modified to respond to bidirectional price and/or dispatch signals.
- Better understanding how a stack of Shiftable loads can be constructed that includes long-term load shifting / rescheduling for predictable shifts (night to day) with short-term dynamic flexibility to manage less predictable shifts (wind variability and hourly-timescale changes).
- Because Shift value is cumulative and not capacity-based, a different set of technology R&D targets from capacity DR are appropriate, suggesting in a sense a bifurcation of Shift from Shed and Shimmy DR. In particular, the reliability of Shed or Shimmy DR at times of binding system need are critical for creating value, but for Shift resources it could be possible to capture significant fractions of the potential value with slightly less reliable dispatch / price response. Work on pilots that are linked with market and electricity system modeling will be needed to identify the characteristics of technology for Shift, Shed, and Shimmy that are needed and help identify a development and deployment pathway.

Interoperability Standards for Plug and Play Grid

A significant barrier to achieving automation in California is the lack of interoperability in

control technologies and communications platforms. Capitalizing on the Smart Grid infrastructure investments and the capabilities enabled by those investments requires significant integration of infrastructure elements. It is challenging to coordinate field devices, communication networks and management and control systems. Bringing together several different infrastructure systems to define an emerging DR capability means overcoming challenges including interoperability, standards and processes. Data from several disparate systems is needed to run a successful DR program. Additionally, the technologies' or processes' span or spectrum engages multiple stakeholders heavily dependent upon systems architecture and business perspective. Each business model requires a different analysis perspective although emanating from the same foundational data

In order to accelerate automated DR program and technology deployment, it would be helpful to develop a framework for interoperability standards that streamlines processes and flexibly addresses different business models and their attendant system architectures. The OpenADR Alliance has developed a set of standard data models for interoperable DR communications. For communicating devices, the ZigBee Smart-Energy Profile has been developed to create a standard and interoperable protocol that connects smart energy devices in the home to the Smart Grid. These standards assist in moving the market towards a plug and play grid, and facilitate the realization of AMI capital investments. We recommend that the CPUC continue to the use of an interoperability standards framework that can accelerate cost effective DR technology adoption and automated DR service capability provided to the grid.

Distribution System Automation

Distribution automation can be defined as automation used in distribution system planning, operation and maintenance, including transmission system, interconnected distributed energy resource (DER) and automated end-user interface communications. Automation can drastically improve visibility in congested areas, and facilitate DR program deployment and operation aimed at addressing congested local capacity areas. While distribution automation investments can be costly, they build upon the smart grid infrastructure and can provide greater visibility between end users and IOUs. Investments in distribution automation could potentially produce cost savings to ratepayers by reducing outages and advancing interconnected DER deployment that provide grid services in real time, helping to relieve congestion. These investments could be viewed as Virtual Power Plant (VPP) investments that address local capacity and DER integration issues.

Data Driven Decision Making

Using AMI data to target specific customer populations, end uses and technologies can help maximize the effectiveness of DR investments, including addressing customer churn issues. DR program business cases can be greatly improved by data analytics that couple utility demographic data, billing data and AMI data to identify customer populations that:

- Are less likely to move or opt-out of programs
- Provide the greatest load impact
- Are more likely to adopt technologies

Utilities have a tremendous amount of data that could empower the decision-making on investments in technologies and recruitment tactics to improve their DR portfolio performance. A genuine focus on developing the tools and resources for data analytics for customer targeting can improve DR investment performance and consequently benefits to ratepayers and the entities servicing them.

10.4. Opportunities and Recommendations for Future Research

10.4.1. Scenario Analysis

This category includes research topics that may build off the Phase 2 model results and/or capabilities but are largely new and/or separate analyses that are beyond the current model's functionality.

Time Varying Rates and Dynamic Pricing research

- Dynamic pricing programs are potentially some of the most cost effective methods to provide DR, particularly Shift. The IOUs are introducing new time varying rates that encourage load shifting and consumption as pilots, and it is important to incorporate customer responsiveness into our DR analysis, in particular when we examine the Shift service type. We suggest additional research on TOU, day-time super off-peak rates, CPP, variable peak pricing, and hourly day ahead real-time pricing scenarios along with testing the influence of automatically price-responsive devices on those approaches. This additional analysis permits examination of LMDR in a framework simultaneous with supply side DR and EE.
- We recommend that the IOUs undertake pilots that examine the impact of automated devices that respond to price signals dynamically to determine the effectiveness of automated DR enabling technologies and the incremental impact that technologies can provide in residential and commercial customer sectors.

Distribution System Level Benefits of DR

- The current DR potential study has provided limited insight on the value of DR at the distribution system level, rather, the study focused on bulk power system DR potential. Future work should utilize the methods developed in the current study and develop the capability to conduct the supply curve framework to constrained distribution feeders and assist in determining the value of DR to the distribution

system. Key contributions are being made by other policy research that could be used to help focus investment in DR and DER broadly (e.g., DRP's LNBA and ICA outcomes and similar).

- Analyses that examine the impact of targeted DR customer recruitment for local capacity relief using granular customer and IOU distribution system data could identify potential load reduction within constrained distribution feeders from **targeted marketing** to particular residential, commercial, & or industrial customers. Optimized recruitment means more cost-effective capacity reduction where you need it most. Customers with higher kWh usage tend to have higher coincident peak load at system level- but what about distribution level?

Multi-DR Program Participation

- The current modeling framework analyzes the DR potential of given customers, end-uses, and technologies based on single-program participation. Analyzing DR potential in a multiple-program participation framework will allow us to understand the impacts such as a reduction in cost due to increasing the usage of enabling technologies or loss of DR potential for programs that may be competing for the same resources. This work will consider both technical impacts on the potential of DR as well as a review of policy and baseline issues. This analysis would significantly add to the capability of the current modeling framework and would require new modules, input structures, and accompanying analysis.

Unified IDSM potential model with EE and DR.

- The bottom-up modeling framework we developed could be augmented to estimate the joint potential for EE and DR among other DSM measures to serve the needs of the grid in a unified DSM potential framework. This analysis would be an expansion and improvement of the current "co-benefits" framework of evaluating IDSM. Further work is needed on evaluating what measures provide the best benefits of energy efficiency, DR, and integrated DSM systems. This work could also include site-specific impact analysis to evaluate various costs and benefits to individual customers.

Contingency Values of DR

- A key limitation of the current study is the omission of evaluating the value of emergency DR. Emergency DR can be thought of as voluntary or mandatory load reduction that is critical to maintaining stability in the bulk power system and is rarely called. This oversight impacted the results of the study by imposing an extremely low value of DR on a system that is not restricted by capacity. This analysis could examine the pros and cons of using RESOLVE to evaluate the value of DR, and will look to understand what other value streams exist and how we can best incorporate them into the modeling framework.

10.4.2. Model Enhancements

This category of priority topics includes work that improves the functionality, usability, and accuracy of the current model framework.

Public Tool, Model Training and Tutorials.

- A public tool that is based on production-level code could have a user interface for dynamic exploration of model inputs and/or tools for facilitating expert use of the software capabilities through an application programming interface (API). LBNL would collaborate with the CPUC and other stakeholders on the specific features of a public tool and the capabilities included in the code.

Expanded Study of Flexible Electric Loads

- The Phase 1 and Phase 2 study focused on loads that are highly likely to be significant contributors to the DR resource by 2025. Further analysis of other loads that could be significant in the future will help utility emerging technology programs focus on key areas of opportunity. These include: refrigerators and other large appliances, plug loads (residential and commercial), electric water heaters, thermal cool storage, electric space heaters, HVAC and variable frequency drives, and municipal water pumping.
- DR through Codes and Standards – The current study has only limited consideration of technologies in Title 24. Additional exploration of the role of T24 and new buildings in the next 10-15 years would help understand the role of new construction and the role of T24 retrofits of automated DR systems. There may also be opportunities to consider DR in Title 20.

Electric Storage Co-Benefits, Value and Use Beyond DR

- There is potential for many customers to install electric batteries to ensure the home or facility will have electricity if there is a grid outage. Others install storage to reduce peak demand charges, manage TOU rates, or optimize self-generation. Additional research is needed on the storage economics to consider DR within the other values that electric storage offers and conduct this analysis with storage as an IDSM system.

Additional Analysis by IOU

- The current study was developed to provide high level analysis capability to forecast the magnitude (MW) of future DR at the bulk power system and to value the system level DR using advanced valuation methodologies. Further work that evaluates each IOU independently could help develop customer sector specific analysis for each IOU.

Electrification Scenario Analysis

- Aggressive future electrification scenarios for California have been identified as a likely necessity for the state to meet its GHG goals, however the impacts of these scenarios on the baseline loads, and therefore DR availability, have not yet been studied. This analysis would involve altering baseline loads to capture increased penetration of electric end-uses such as water heating, cooking, and vehicles, and examining the resulting grid impacts and DR potentials.

Deeper Study of the Agricultural Sector's DR Potential

- The agricultural sector in California has been identified as one of the industrial sectors with very low participation rates and an untapped technical potential (see Olsen et al., 2015). Deeper study of the emerging technologies (e.g., advanced sensing and automation) could identify highly flexible VFD/pumping loads. This analysis can also tie into State initiatives on water-efficient technology demonstrations.

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